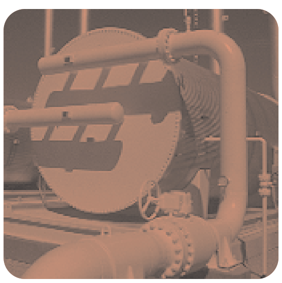
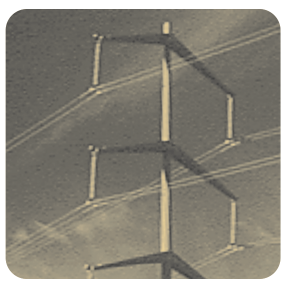
California Energy Commission
Gray Davis, Governor

California Energy Outlook

Electricity and Natural Gas Trends Report

Staff Draft

September 2001

200-01-002

CALIFORNIA ENERGY COMMISSION

Al Alvarado
Project Manager

Al Alvarado
Richard Grix
Jairam Gopal
Todd Peterson
Richard Rohrer
Lynn Marshall
Rick Buckingham
Mike Jaske
Robert Grow
Principal Authors

Karen Griffin
Elizabeth Parkhurst
Technical Editors

Karen Griffin
Manager
Electricity and Analysis Office

Bob Therkelsen
Deputy Director
Systems Assessments and
Facility Siting Division
Steve Larson
Executive Director

Contents

Executive Summary

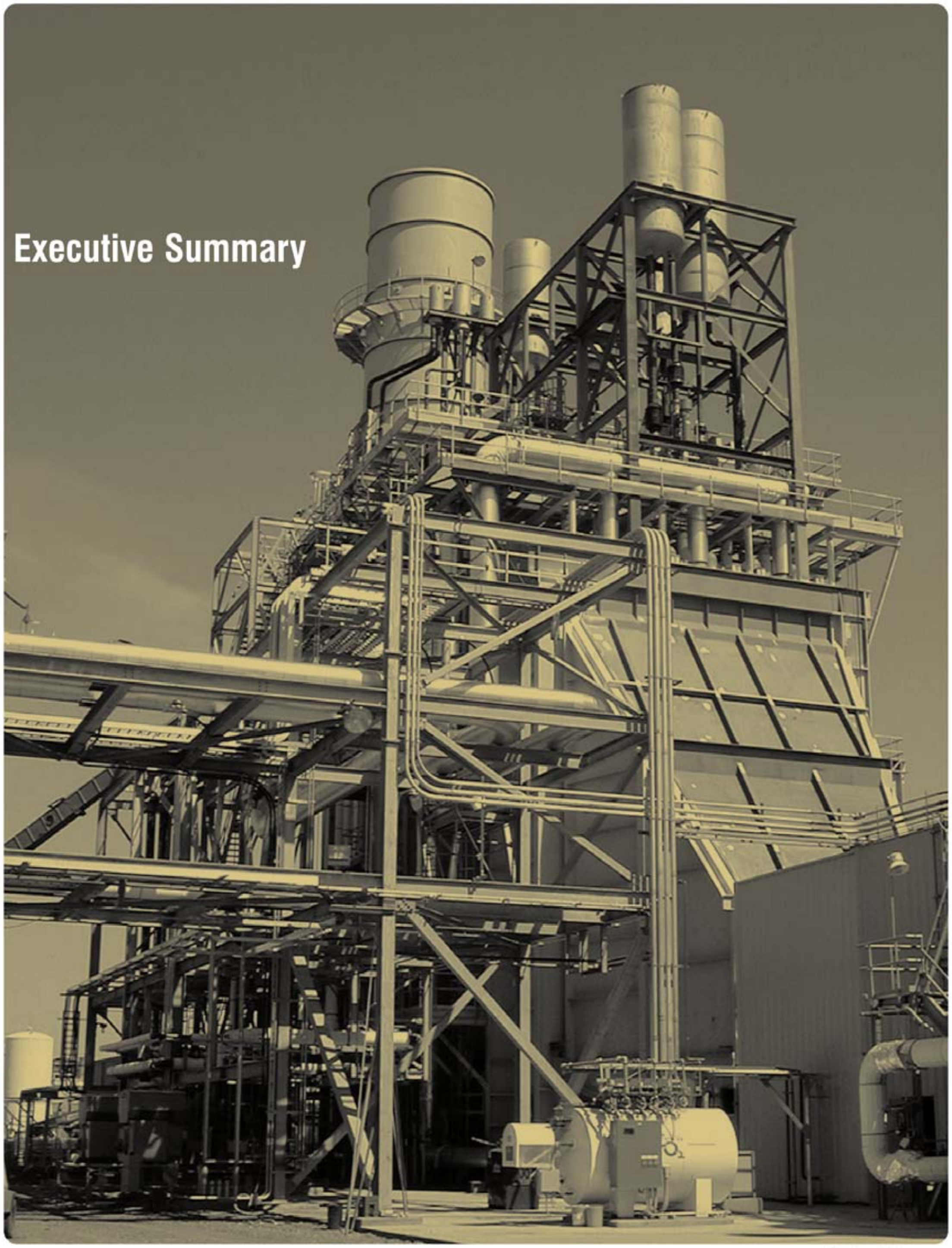


Photo: Laura Frank

EXECUTIVE SUMMARY

The *California Energy Outlook: Electricity and Natural Gas Trends Report* responds to the requirements of Section 25553 of the Public Resources Code. These requirements were enacted by Assembly Bill (AB) 970 (Ducheny) Chapter 329, Statutes of 2000, and signed into law by Governor Davis. Among other provisions, AB 970 requires the Energy Commission to provide the Governor, the Legislature and the public with accurate information on California's electricity supply, demand and conservation trends.

The report presents the energy supply and demand trends of the past decade to provide perspective on current events, along with an overview of expected developments for 2001 and a long-term demand outlook through 2010. The energy trends cover both electricity and natural gas developments. Electricity generation developments have important implications to the natural gas market and fuel delivery infrastructure, given that natural gas is the single largest fuel source for California electricity generation.

The report focuses on key events and trends that affect near-term risks to ensuring an adequate supply electricity. The report also examines electricity demand, load management, and natural gas infrastructure developments. Although many market-design issues need to be resolved to improve competition and maintain system reliability, this report does not address market structure problems. The California Independent System Operator, Federal Energy Regulatory Commission, utility distribution companies and academic institutions are studying the various structural problems with California's market design.

The remainder of the "Executive Summary" provides an overview of recent developments and issues that are addressed in the report.

Background

Electricity and natural gas markets brought unexpected developments in 2000, resulting in exorbitant prices and serious reliability risks. These developments were due to two key problems: limited supplies of electricity and natural gas throughout the west and flaws in the design of the new market which allowed market participants to directly influence wholesale prices.

Although normal fluctuations in the natural gas market helped increase electricity generation costs, some allege that market manipulations increased electricity and natural gas costs beyond reasonable competitive levels. Whatever the causes, California's efforts to substitute competition for cost-based regulation in the generation sector of the electricity industry have fallen substantially short of expectations.

Electric utilities have already lost billions of dollars attempting to serve load, pushing the Nation's largest utility into bankruptcy. Consequently, the State committed billions of dollars to purchase power to restore order to the electricity market. All of these costs may eventually be passed on to consumers, along with the risks that the energy markets may affect the California economy as a whole.

The transition to a workable competitive market is clearly in jeopardy and will require stronger government involvement to protect the interests of California citizens. To begin to address this need, the Governor has developed an Energy Plan, and numerous Legislative bills have now been proposed to stabilize the market volatility and moderate risks for this summer's and next year's peak load season. However, the crisis can only be resolved if both state and federal regulators take measures designed to return the markets to some semblance of normal operation.

Chapter 1 explains the purpose and background information on the different topics covered in the report. The following sections provide a synopsis of each chapter in the report.

California's Electricity System

Chapter 2 provides a general description of the bulk electricity system. This chapter describes the current generation system, how the system has developed over the years, and the trade relationship that the interconnected transmission grid creates with the rest of the western region. This chapter also compares California and United States energy trends to add perspective and discuses some of the myths and misconceptions of the market.

An understanding of the electricity resource characteristics and transmission network provides the basis for analyzing future needs and market developments. California is a regional power system that includes a diverse mix of natural gas, renewable, hydroelectric and nuclear generation resources. California imports between 20 to 30 percent of its electricity needs from eleven western states, and western Canada and Mexico. The interconnection of regional power systems throughout the west provides trade opportunities enhanced by the diversity of generation resources and regional differences in load patterns.

Energy Markets in Transition

Chapter 3 summarizes recent developments in the California electricity market. This chapter includes a general overview of the price volatility in the wholesale power market, the decline in system reliability, and retail price developments. This chapter sets the stage for understanding the current electricity problems.

Although problems were encountered from the beginning of industry restructuring, the market functioned without serious problems during its first two years of operation and market prices tracked expectations. However, California's electric system infrastructure and the new market institutions developed significant problems in the summer of 2000, which continued and even worsened during the winter.

Electricity Supply Adequacy in California

Chapter 4 explores the uncertainty about whether the western region has adequate electricity generating capacity to serve California's needs. This chapter looks at recent electric generation supply trends and provides an outlook for the next several years. While several thousand megawatts of new power plant capacity are under construction in the state, even more are currently under review in the Energy Commission's siting process.

Electricity generation reserves have been consistently declining in California and the West since 1993. As the Independent System Operator's AB 1890 Section 350 report[1] and the Energy Commission's Heat Storm Study[2] note, California has faced increasing supply adequacy risks for several years. A decline in reserve capacity has made the State's electric system more vulnerable to market manipulations and disruptions due to unexpected events, such as higher than expected outages of generation facilities. During some of these events, the Independent System Operator directed utilities to curtail loads to maintain the overall reliability of the transmission grid. Most curtailments occurred during the winter months when load is significantly lower than summer peak demand periods.

New generation capacity and demand reduction measures that are needed to reverse this trend are currently under development. The outlook for meeting the 2001 peak demand is encouraging, especially with the mild weather California has enjoyed to date. The outlook for the next several years is optimistic.

Electricity Consumption Trends

Chapter 5 provides an overview of recent California demand trends and an outlook for the next decade. This chapter also provides an overview of recent trends in electricity demand growth by region and industry sectors, including the changes in electricity demand under normal and above average temperature conditions, since temperatures vary from year to year. A summary of the Commission's latest demand outlook is included, with an updated forecast expected at the end of the year.

California electricity peak demand continues to grow at about 2 percent per year on average. However, some regions are experiencing explosive growth, such as in the Silicon Valley

---

[1] The *AB 1890 Section 350 Report* can be found on the ISO website at: [http://www.caiso.com/thegrid/operations/TRR/index.html] and *Task E, Assessment of Resource Supply* at: [http://www.caiso.com/thegrid/operations/TRR/taske7-14.pdf]

[2] *High Temperatures & Electricity Demand: An Assessment of Supply Adequacy in California, Trends and Outlook* can be found at:[http://www.energy.ca.gov/electricity/1999-07-23_HEAT_RPT.PDF]

region, causing unique local system problems. In addition, new residential development has shifted to the Central Valley region, increasing peak air conditioning loads that fluctuate with temperature conditions. As the population continues to grow, technological advances, energy-efficiency improvements, and increased competition in energy commodities are expected to moderate future energy demand increases.

Energy Efficiency Resource Opportunities

Chapter 6 summarizes current efficiency programs, including the past savings from efficiency improvements. Efficiency programs reduce the energy dependence of California's economy, make businesses more competitive, and allow consumers to save money and live more comfortably.

As an energy efficiency program, load-reduction opportunities are an important element in balancing supply requirements. Energy efficiency programs defer the need for new generation or transmission capacity, prevent environmental degradation, and help consumers control their utility bills. Since 1975, the displaced peak demand from past efficiency programs has been roughly the equivalent of eighteen 500-megawatt power plants.

Temporary programs are now being put in place to provide immediate relief in the summers of 2001 and 2002. Although these programs target demand reductions during the summer peak demand period, many programs will also produce year-round savings through improvements to lighting, water pumping, and heating and cooling system efficiency. There is also an observable change in consumer behavior due to recent high prices, the number of Independent System Operator emergency alerts, and extensive press coverage of the energy crisis.

Western Natural Gas Systems

Chapter 7 provides an overview of the natural gas production and delivery system. This chapter includes a general description of the natural gas pipeline system, the regions where proven reserves and potential resources are located, California production trends and a long-term supply outlook. To understand the mechanics of the natural gas market in California, it is essential to understand all of the market fundamentals.

The clean-burning characteristics of natural gas and its price have made it a premium fuel of choice in California, especially for power generation. However, gas produced in the state satisfies only about 15 percent of the statewide demand. The remainder is obtained from other western states, Alberta and British Columbia. A complex grid of pipelines transports natural gas from producing regions to California consuming regions.

Overall, adequate supplies of natural gas are expected to be available from these regions throughout the next decade. In today's competitive market environment, changes in supply, demand, or price in one region affects all other regions.

California Natural Gas Developments

Chapter 8 assesses the current and future natural gas market issues confronting California. This chapter includes an overview of consumption trends, supply adequacy concerns, pipeline constraints, and storage needs. Although natural gas supplies are expected to remain generally plentiful over the long term, market forces and regulatory events may cause significant short-term fluctuations in natural gas supplies and prices. California has already experienced fluctuations and price volatility during the past year.

Two issues are likely to affect the supplies of natural gas in California. First, infrastructure issues are likely to constrain natural gas supplies over the next year. Pipeline capacity and ability to refill natural gas storage facilities will be limited over the next year. These problems may limit the availability of fuel supplies to meet seasonal demands though 2001 and early 2002. Second, the natural gas and electricity markets are tied together, with natural gas being the fuel of choice. Natural gas consumption by power plants is volatile since electricity demand may fluctuate significantly depending on weather variations. Such uncertainties raise concerns about the future impact of supply adequacy on electricity markets.

Synopsis of the Technical Appendices

The following is a synopsis of the technical appendices of the report. The appendices include several study topics that are beyond the scope of the AB 970 reporting requirements.

Demand Responsiveness in Electricity Markets

Appendix A describes how demand responsiveness programs could give consumers and other end-users more control over their electricity consumption. This appendix provides a discussion about why consumers do not respond to real price fluctuations, a description on how demand responsiveness could work and an overview of activities currently underway to provide the right pricing signals to consumers.

Currently, consumers have little motivation to reduce consumption when prices to generate electricity are high and supplies are tight, threatening the reliability of the system. This problem arises because consumers do not directly experience the high prices during high demand periods, as consumer rates are fixed due to regulatory requirements. Moreover, consumers lack the means to respond even if they wanted to because they are not informed of the hourly prices in the wholesale markets. Furthermore, consumers do not have the meters to measure their hourly consumption patterns.

Instead of a market where demand elasticity is governed by consumer preferences and technology costs, consumption behavior is moderated by legal requirements that fix rates. Changes that increase demand responsiveness require an explicit focus on the design of the retail market structure.

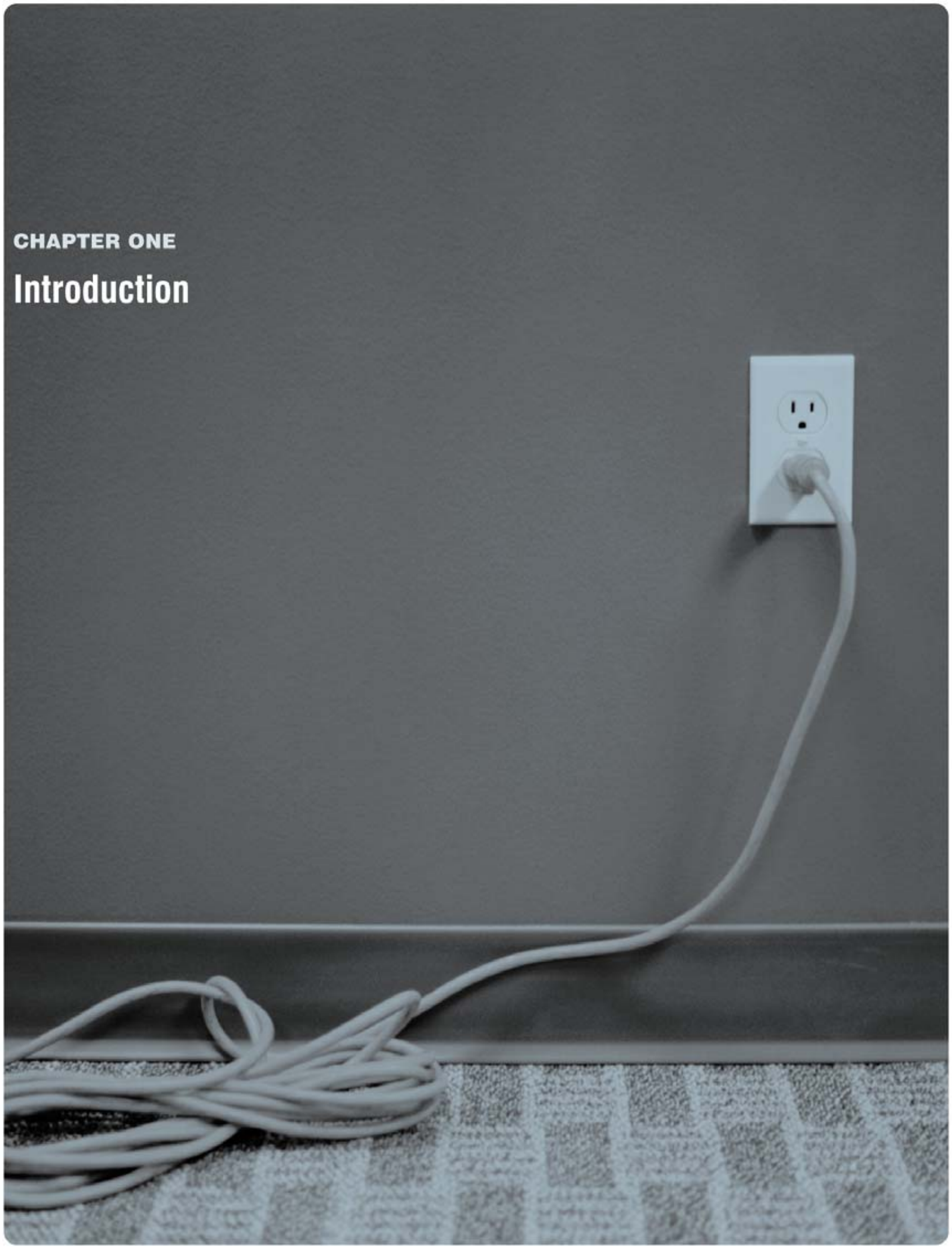
Wholesale Electricity Pricing in a Sustainable Market

Appendix B provides an overview of the different factors that affect wholesale electricity prices. This appendix illustrates the price levels that an ideal market would likely produce if California were to have a sustainable market. "Sustainable" means to have a structure that is fair to both buyers and sellers, encouraging continued market transactions.

Any market design must provide generators with enough revenue to maintain the operation of some of the existing infrastructure and attract additional investment as needed. Even if analysts can ascertain what would be a reasonable cost of generation, it is still extremely difficult to develop a market design that will send the appropriate price signals to generators for new development. The difficulty stems from the natural features of electricity as a commodity.

CHAPTER ONE

Introduction



Chapter 1
Purpose of the California Energy Outlook Report

The California Energy Outlook Report presents the energy supply and demand trends of the past decade to provide perspective on current events, along with an overview of expected developments for 2001 and a long-term demand outlook through 2010. The energy trends cover both electricity and natural gas developments. Electricity generation developments have important implications to the natural gas market and fuel delivery infrastructure, given that natural gas is the single largest fuel source for California electricity generation.

The report was prepared in response to the requirements of Section 25553 of the Public Resources Code. These requirements were enacted by Assembly Bill 970 and signed into law on September 6, 2000. The legislation requires the Energy Commission to:

> Undertake a continuing assessment of trends in the consumption of electric energy and other forms of energy and analyze the social, economic and environmental consequences of these trends.

The legislation also directs the Energy Commission to independently analyze "forecasts in relation to statewide estimates of population, economics and other growth factors and in terms of the availability of energy resources, costs to consumers and other factors." Furthermore, the Energy Commission must recommend measures that could be undertaken to ensure adequate supply and energy conservation. Assembly Bill 970 specifies that the Energy Commission is required to submit the trend analysis within 120 days after the effective date of the legislation.

The Commission's Electricity and Natural Gas Committee released a draft "AB 970 Trends Report" in December 2000, but later decided to shift the scope of the report to only address current supply and demand developments. The December report originally included recommendations and focussed on market design issues, which was already under investigation by the Legislature and other regulatory agencies. Considering that numerous legislative bills were introduced earlier this year to address market concerns, infrastructure issues became a more prominent concern that the Commission could address.

Additional legislation has since been introduced to increase energy conservation programs. The Energy Commission has also been implementing emergency siting procedures to accelerate the licensing review of new generation proposals. The Department of Water Resources also signed a number of long-term contracts to secure a reliable supply of electricity for the future. Given these developments, the Energy Commission decided that additional time to monitor recent energy market trends and provide an understanding the related implications was warranted to prepare a more useful document.

The report focuses on key events and trends that affect near-term risks to ensuring adequate electricity and natural gas supplies. The report also examines electricity demand, load management, and natural gas infrastructure developments. Although many market-design issues need to be resolved to improve competition and maintain system reliability, this report does not address market structure problems. The California Independent System Operator, Federal Energy Regulatory Commission, utility distribution companies and academic institutions are studying the various structural problems with California's market design.

CHAPTER TWO
California's Electricity System

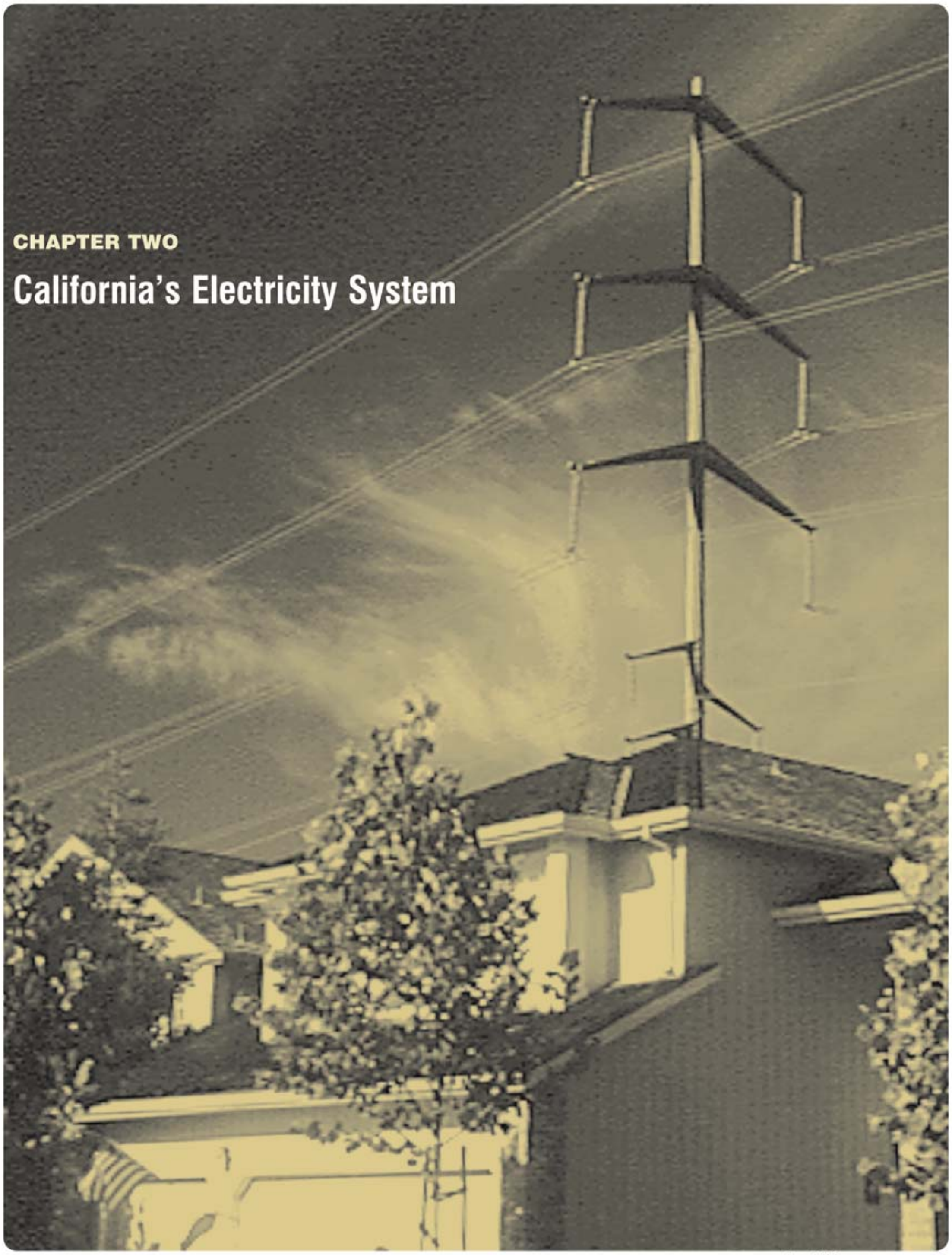


Photo: Al McCuen

Chapter 2
California's Electricity System

Chapter 2 describes the State's current bulk electricity system. An understanding of the characteristics of California's current electricity resources and transmission network provides a foundation for analyzing future need and development. This chapter describes the current generation system, how the system has developed over the years, and the trade relationship that the interconnected transmission grid creates with the rest of the western region. This chapter also compares California and United States energy trends to add perspective and discuses some of the myths and misconceptions of the market.

California and the ISO

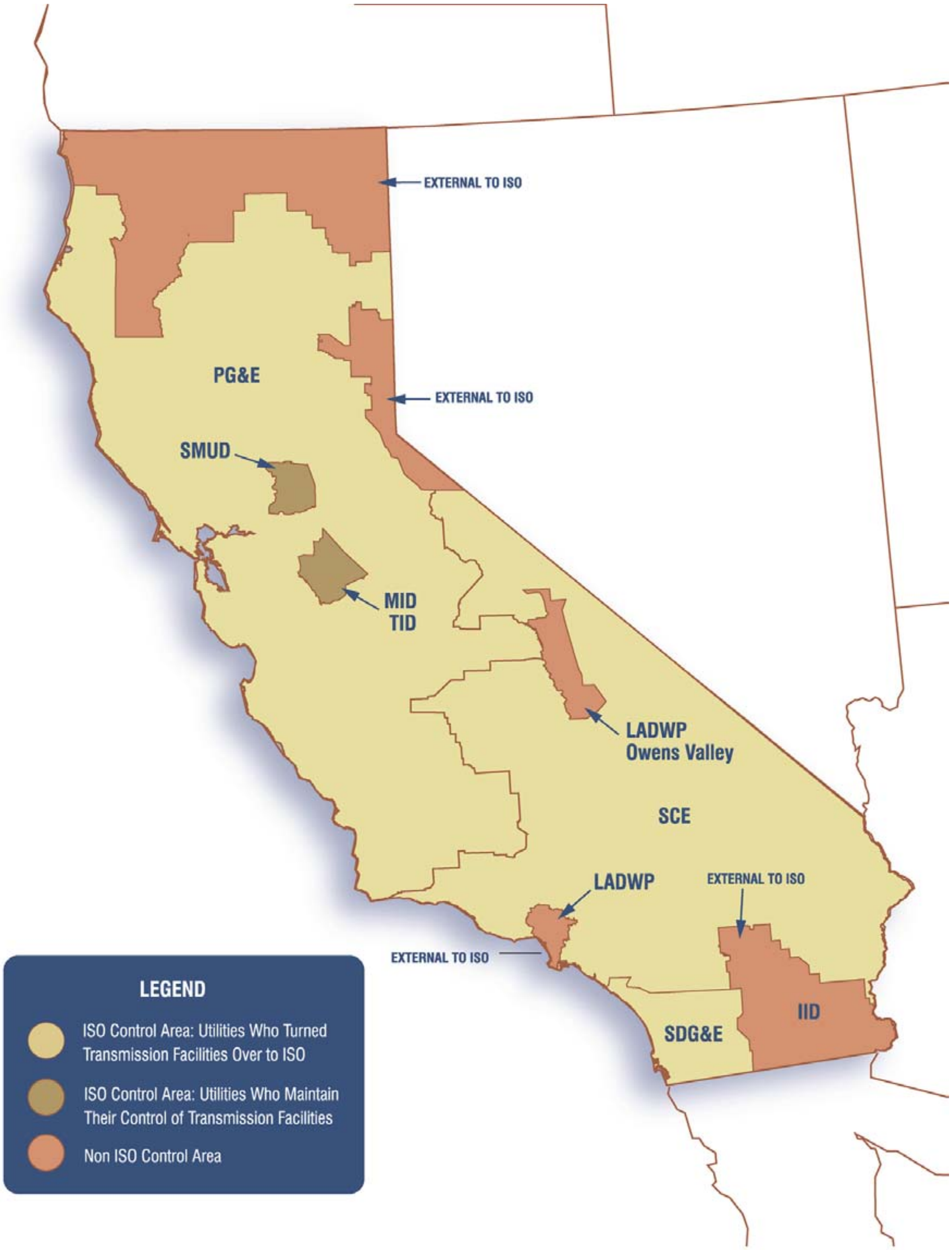
California has a vast and complex electricity system that includes over 1,000 power plants. These plants provide power to over 13 million customers over 27,000 circuit-miles of transmission lines. The operations of these facilities are controlled through regional control centers, primarily the California Independent System Operator (ISO).

The ISO Control Area includes the service territories of most Californian utilities. These utilities fall into two groups – those that have transferred operational control of their transmission facilities to the ISO and those that have interconnection agreements with ISO-controlled utilities. The investor-owned utilities (PG&E, SCE, and SDG&E) originally had operational control of their respective transmission facilities, but were then required to transfer control to the ISO as a result of AB1890. Publicly owned utilities were not required by law to surrender control of their transmission assets to the ISO.

The City of Vernon has since volunteered to transfer control of their facilities to the ISO. Many of the remaining municipal utilities with interconnection agreements within the ISO control area have not relinquished control of their transmission assets. Finally, there are some utilities who have their own control centers (Los Angeles Department Of Water and Power, the Cities of Burbank, Glendale and Pasadena and Imperial Irrigation District) and therefore are not part of the ISO's Control Area. Sierra Pacific and Pacific Power and Light have customer territories that cross into the California border areas, but are not part of the ISO control areas.

Figure 2-1 depicts the three groups of utilities in California. For purposes of this Chapter, "California" refers to the entire state, while "ISO" refers to the service areas served by the Independent System Operator.

Figure 2-1
Independent System Operator Control Area



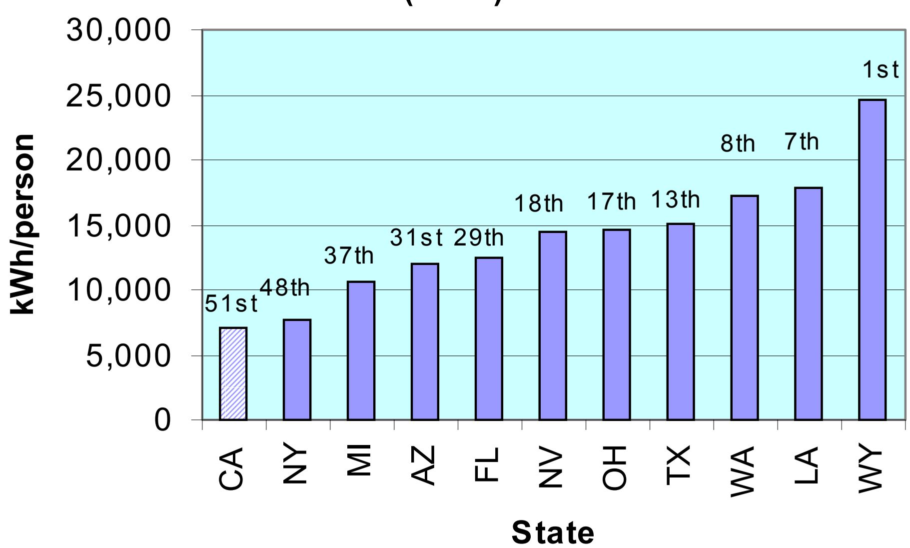
California's Electricity Use

Although the total amount of statewide electricity use is significant, **Figure 2-2** shows that California's per capita consumption is actually quite thrifty. California ranks 51st out of the 50 states and the District of Columbia in the estimated energy consumption per person. Notwithstanding its efficient use of electricity, California's sheer size in population and economy requires a significant investment in electrical production.

Serving California's Electricity Needs

To meet California's electricity load, California has relied upon a large number of power plants with diverse fuels. As can be seen in **Figure 2-3**, California's in-state electricity resources include over 1,000 plants that have a combined nameplate rating of over 52,500 megawatts. **Figure 2-4** shows that these plants use a diverse mix of power including hydroelectric, fossil fuels, nuclear and renewables.

Figure 2-2
Total Electric Consumption per Person
In the 50 States and District of Columbia
Sample States
(1999)



Source: Energy Information Administration *State Energy Data Report 1999*

CALIFORNIA'S ELECTRICITY MARKET

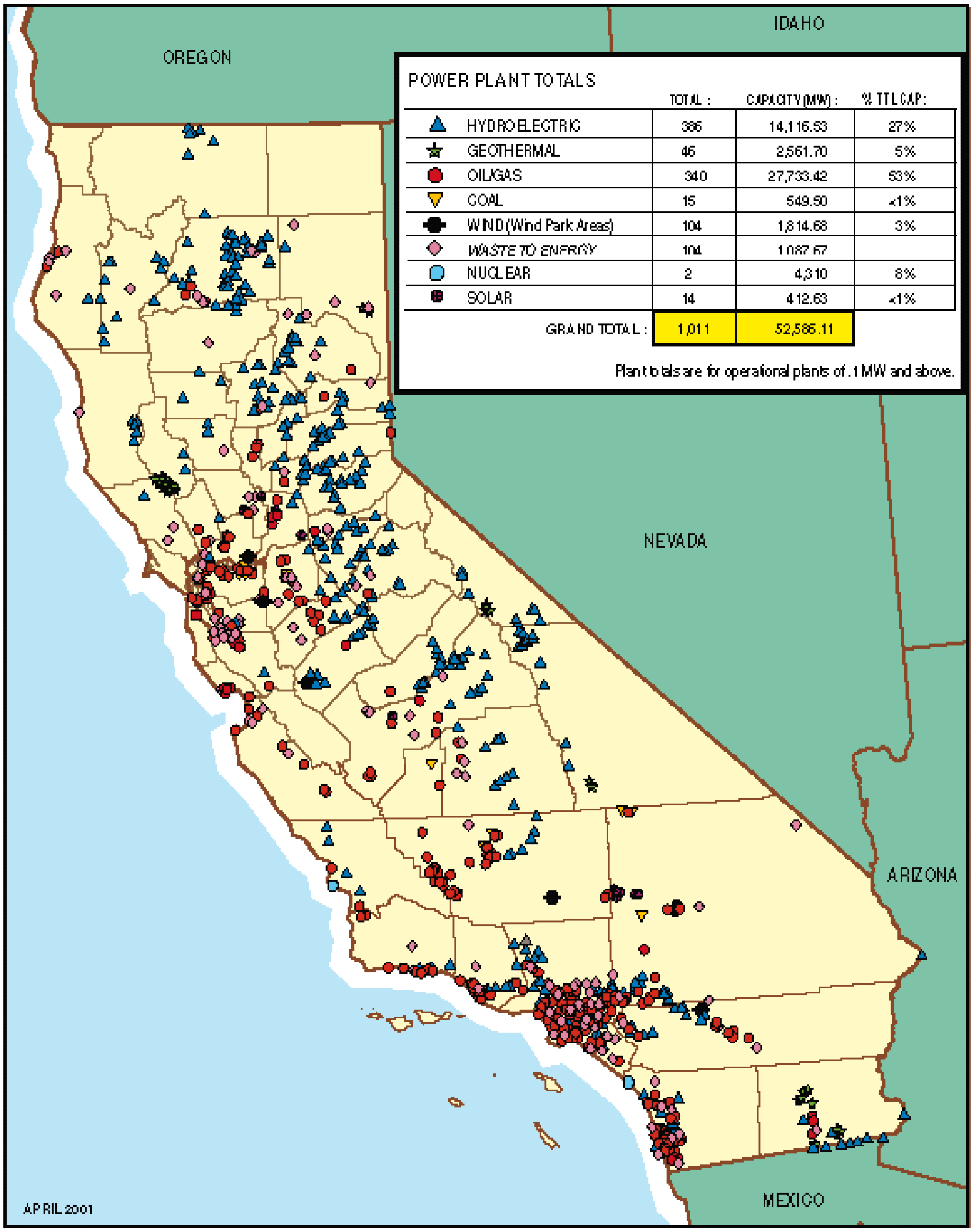


Figure 2-4
California's Power Plants by Type
(Total Capacity - 52,586) (2001)

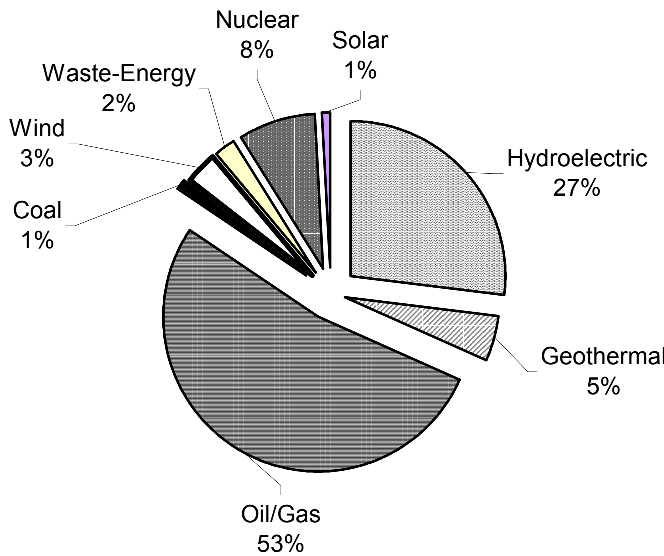
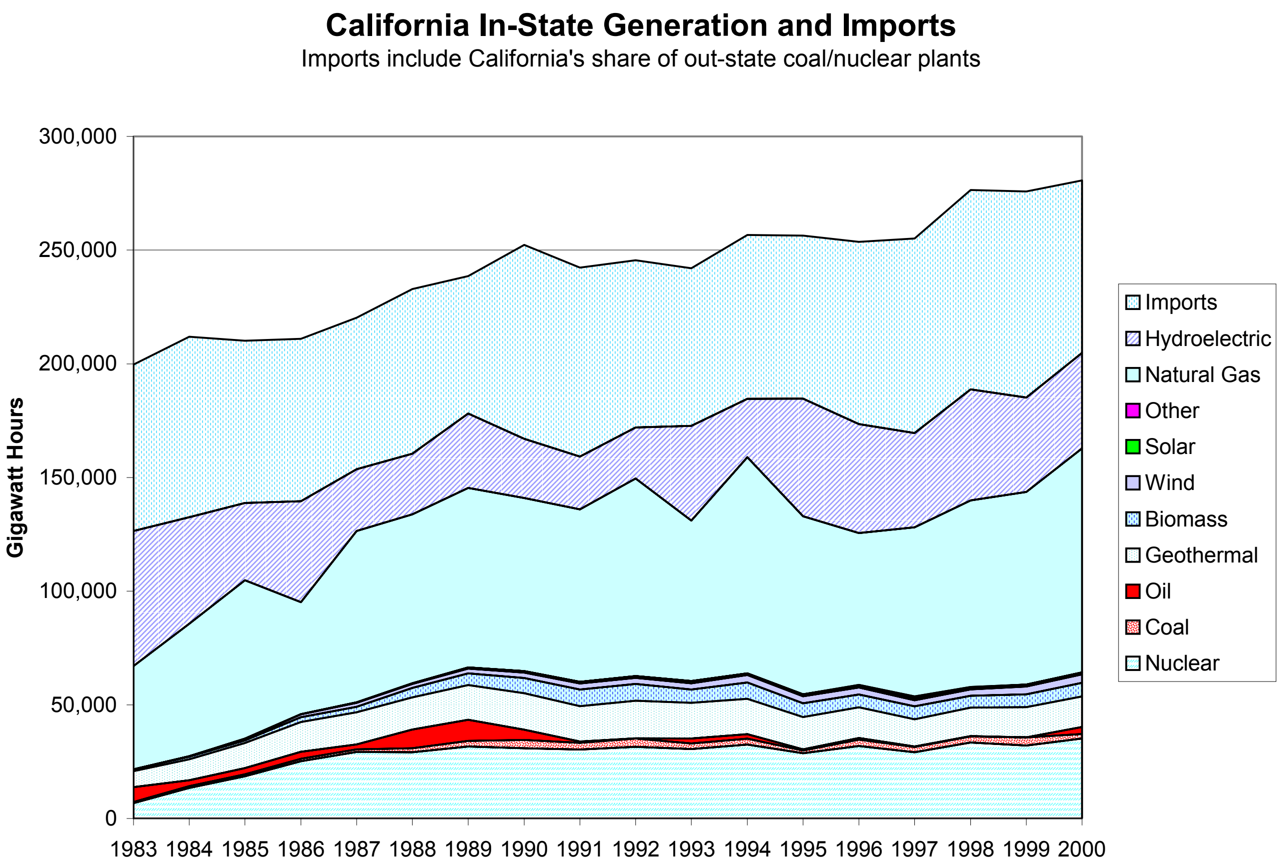


Figure 2-5 shows the California electricity generation trends, including out-of-state imports, for the period of 1983 to 2000. The figure contains preliminary estimates for the year 2000. "Imports" include net power purchases and the generation from facilities that are owned by California utilities (i.e., ownership shares from the Palo Verde nuclear facility, or the Mohave and Four Corners coal generation facilities).

Although the total California power plant capacity is approximately 52,500 megawatts, individual plants do not always produce power at their rated capacity or simultaneously with the overall electric system. For example, wind plants tend to generate at levels close to their rated capacity during windy days. However, hot summer peak days are noted for the lack of breezes. Operators must recognize the difference between "rated" capacity and the level of capacity that they can "depend" upon can significantly differ.

Figure 2-5



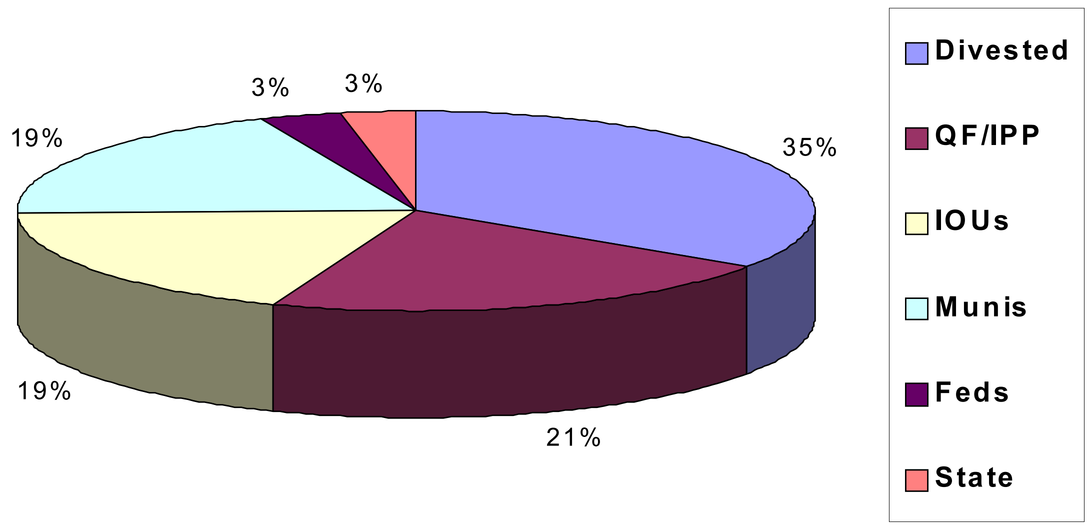
Note: 1983-1999 generation information can be found at: [http://www.energy.ca.gov/electricity/electricity_gen_1990-200.html]

In addition, since existing generation at times can run at very high levels, breakdowns occur periodically. Generally, about 3,000 megawatts are not available on average due to planned and forced outages.

Ownership of California's Generation

As shown in **Figure 2-6**, California's generation is owned by many entities. Note that the generation formerly owned by the investor-owned utilities (labeled as "Divested") represents only one-third of California's generation. There is still a large percentage (approximately 44 percent) of total generation that is owned by investor-owned and municipal utilities, plus other state and federal entities.

Figure 2-6
Generation Ownership

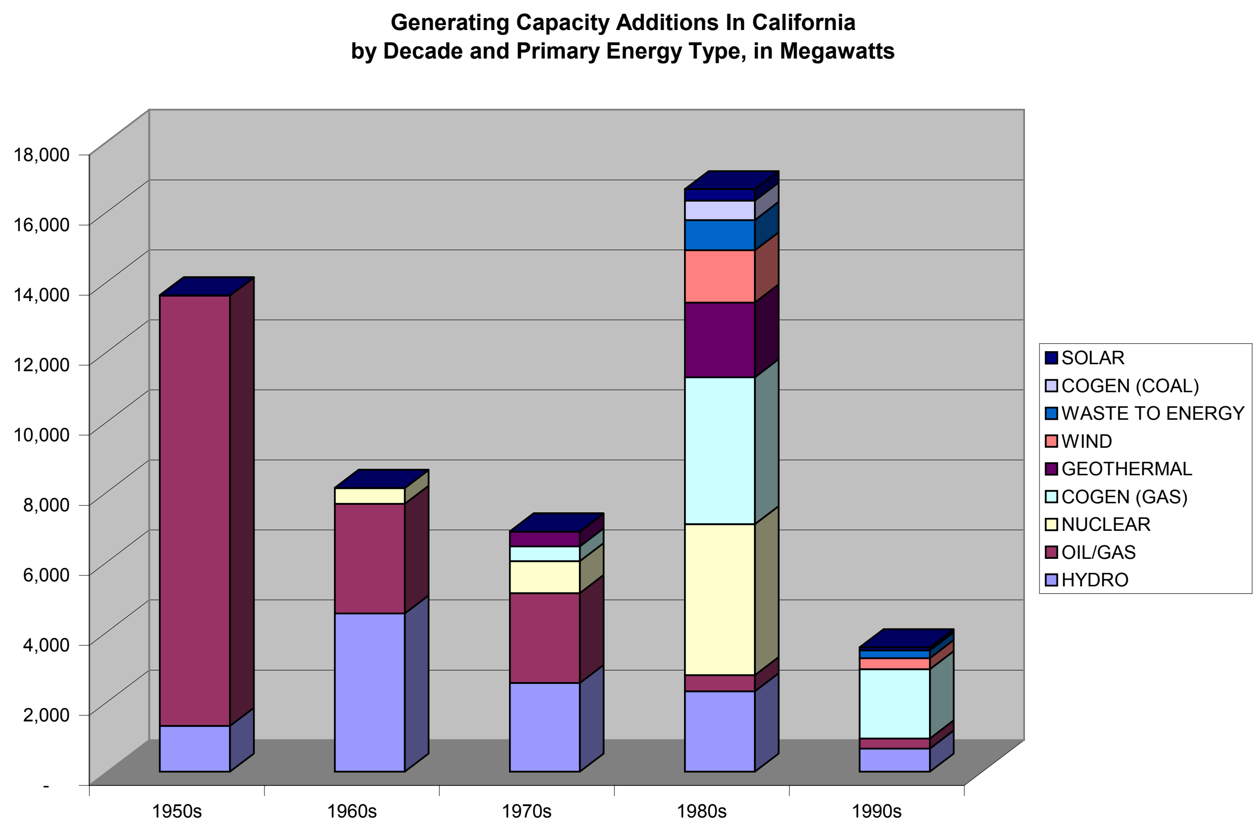


Source: California Energy Commission

Some Observations of California's Power Plants

The variety of California's power plants is reflected in the type of development that has occurred over the decades of the twentieth century. Each decade emphasized different philosophies in building power plants. In the very beginnings of California's electric history, the development of hydroelectric generation was always a major focus. However, as California grew, hydroelectric generation could not keep up with demand. Accordingly, utilities began to look for other sources of electricity. In the 1950s, a large growth of oil/natural gas fired generation appeared. A balance of thermal/hydro construction continued in the 1960s. In the 1970s and 1980s, new technologies appeared in the form of nuclear, geothermal, and renewable generation helping to serve California's electricity demand. In the 1990s, the industry veered away from large central station generation and developed local cogeneration facilities. A summary of this chronology is shown in **Figure 2-7**.

Figure 2-7



Source: California Energy Commission

Now, at the beginning of a new century, California is looking towards cleaner-firing natural gas generators as central station providers. In addition, California is exploring the development of the smaller and closer-to-load "distributed generation." Such generation can be located in overloaded areas and help mitigate congestion issues on the transmission and distribution grids.

Finally, as shown in **Table 2-1**, almost one-third of the total generating capacity is over 40 years old. Nearly one-half of the total capacity is over 30 years old. Older plants tend to require more maintenance outages and can incur more unexpected breakdowns. Therefore, California needs to plan for more power supplies to meet its annual load requirements.

Table 2-1
Aging Facilities

	Power Plants (#)	Power Plants (%)	Capacity (MW)	Capacity (%)
Total	971		53,000	
Over 40	128	13.2	17,200	32.1
Over 30	181	18.6	26,000	48.6

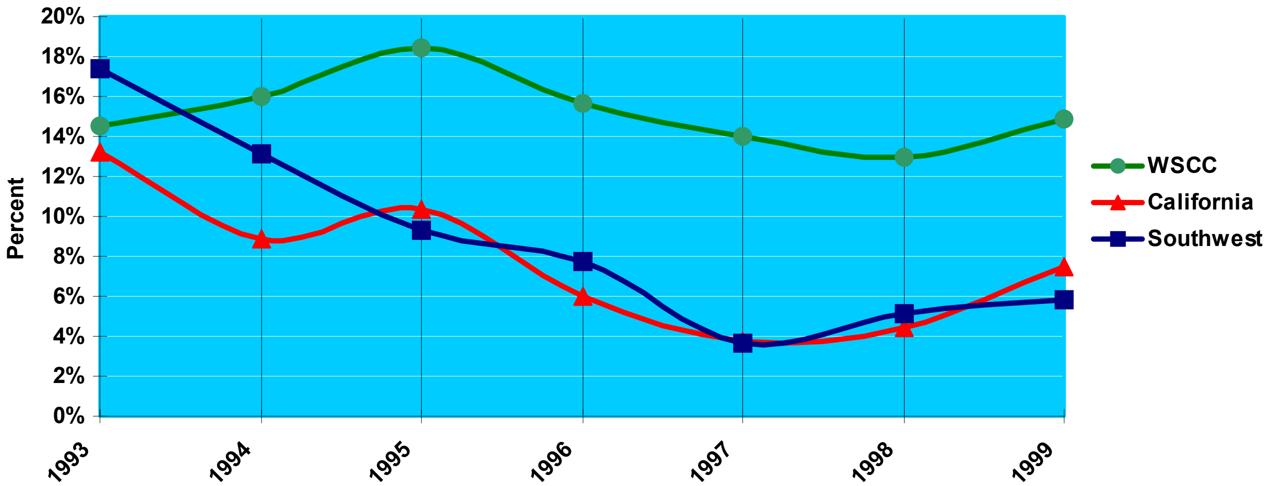
Source: California Energy Commission

How Much Generation Does California Need

California's utilities are part of a large Western group of entities known as the Western Systems Coordinating Council (WSCC). The WSCC, organized in August 1967, provides the coordination that is essential in operating and planning a reliable and adequate electric power system for the western part of the continental United States, Canada, and Mexico. The WSCC requires member utilities to provide "reserves" (i.e., additional available generation beyond what it is needed to meet load) that can be used for real-time variations and emergency purposes. The WSCC has adopted its "Minimum Operating Reliability Criteria" which sets forth various percentages (above load) that utility or their control area operators must meet in order to maintain adequate system reliability. Generally speaking, the WSCC requires such utilities/ control areas to maintain, at a minimum, at least 7 percent of operating reserves above load.

Figure 2-8, shows the peak reserve margins for California, the Southwest and for the WSCC as a whole. The recorded reserves include operational generation, not those facilities that were down for maintenance. While the entire WSCC has maintained double-digit margins, both California and the Southwest had declining reserve throughout the 1990s. The method for calculating reserve margins has changed with the restructured market. The reserve margins that the ISO now reports each day is a function the generation that is contractually scheduled for dispatch and does not measure the actual physical availability of total generation in the system. This is discussed at greater detail in Chapter 4.

Figure 2-8
Non-Coincident Peak Demand Reserve Margins
1993 – 1999



Source: Western Systems Coordinating Council, 10-Year Coordinating Plan Summary 1999-2008, October 1999.

Reserve margin can be considered as an index for whether there is more than enough generation available to meet California's needs. California has embarked upon an ambitious and accelerated program for building new generation in the state.

When In-State Generation Is Not Enough

In-state generation is not expected to fully meet the needs of California's consumers. So what does California look to in helping to meet the shortfalls in in-state production? California is a very active importer from other Western states (e.g., hydroelectricity from the Pacific Northwest; coal and nuclear generation from the Desert Southwest). California accesses these other regions through an extensive network of large transmission lines.

During the mid-1960s, expansion of Extra-High Voltage (EHV) transmission line interconnections among utility systems in the West created the beginnings of an interregional system. Transmission interties between utility systems were primarily developed to ensure meeting system reliability requirements by allowing power exchanges to relieve temporary shortages of generation capacity.

Figure 2-9 shows the import capability from the neighboring states. The ratings for the transmission paths can vary seasonally and with different system conditions. Plant outages or high demand levels in certain regions of the state impact the transfer capability of these transmission paths. Specific operating procedures take effect in response to certain conditions to limit the ratings of the major transmission lines into the state to prevent from overloading. Electric utilities and marketers have since come to routinely use the extensive transmission grid to purchase power and energy from eleven western states, Canada and Mexico. In the 1990's, about one-quarter of California's electricity loads were met by out-of-state power purchases, representing annual interregional trade volumes of almost one billion dollars. Utilities have further relied on the ability to import power by purchasing ownership shares in out-of-state generation facilities.

The interconnection of regional power systems in the West has provided broad opportunities for trade due to the diversity of generation resources and regional differences in load patterns. Historically, there has been a substantial excess of electrical generation capacity in the West. Hydroelectric capacity on the Columbia and Snake Rivers that were in excess of local demand, especially during the spring and summer, contributed to a surplus of power in the PNW. Power surpluses in the Southwest resulted from an overbuilding of generation capacity considering that high load growth rates forecasted in the 1970's and 1980's failed to materialize. These surpluses were made available to California, cultivating a robust wholesale power market in the West.

California utilities have been able to rely upon the availability of power from the Southwest with a good deal of certainty. This fact stems from (a) a substantial portion of it being owned by California entities or imported under long-term contract, (b) it being generated by baseload plants - facilities that are most efficiently operated at high levels of output, and (c) a surplus of transmission capacity from the Southwest into California. Yet only a portion of power generated in excess of Southwest regional needs has historically been of use to California buyers. The region, especially the states of Arizona and New Mexico, has a demand profile similar to that of Southern California. Excess energy is primarily available from the Southwest during off-peak hours when demand in both regions is lowest.

Unlike the Southwest, the complementary nature of the California and Pacific Northwest electricity systems makes the two regions natural trading partners. Seasonal diversity allows California to take advantage of power surpluses in the Northwest and provides substantial benefits to both regions. During the spring and early summer, a period of low demand and high supply in the Northwest, surplus power is available for export to California. Loads in the Northwest are highest in the winter, when capacity in California far exceeds in-state requirements. However, imports from the Northwest to meet peak demand during the summer cannot be relied upon to the same extent as imports from the Southwest since there is substantial variation in hydro availability from year to year.

Figure 2-9
California's Electricity Import Capacity

Although California utilities had abundant generation capacity, purchases of power from the Pacific Northwest, Southwest, Canada and Mexico have brought significant savings for California consumers. Out-of state power purchases were generally used to displace expensive generation produced in California. Furthermore, out-of-state resources also helped to moderate the cost of purchasing power from qualifying facilities' generation. These resources also allowed utilities to defer the need to build new generation facilities and reduced the impacts of electric power generation on air quality, such as in the South Coast Air Basin. Consequently, out-of-state power resources created a competitive downward pressure on the cost of alternative generation supplies.

The regional electricity markets have since changed and consumption is increasing to levels that now make use of all existing generation capacity. Where imports were once primarily used to displace in-state generation and reduce costs, the ISO now considers electricity imports to be an important resource needed to balance summer reliability needs. Municipal utilities in the state are also relying on imports to satisfy a significant portion of everyday electricity demand. This reliance may change over the next ten years, depending on the level of new generation entry into California. The success of potential load management and demand responsiveness programs are also important for reducing peak demand and reliance on imports.

Some Myths About California's Electric System

There have been numerous assertions about the reasons that caused the recent electric market crisis in California. Some of these assertions reflect a misunderstanding of actual developments. These assertions, or "myths," about California have been pervasive and will require time to be dispelled. Two of the myths are examined below.

Myth: Recent Growth in Energy Demand Was Unexpected

One of the recent myths is that California's growth in its demand for energy has been unexpectedly strong and therefore power plant builders have been caught offguard. As detailed in Chapter 5, the California Energy Commission's 1988 forecast for year 2000 included a projection of annual peak demand. In fact, the summer of 2000 had a lower peak than the forecast had projected. From year to year, California has had variations in its energy consumption (much of the variation is due to weather). However, California's growth in demand has been predictable and moderate.

To further illustrate that energy growth has not been extraordinarily fast, **Table 2-2** shows some relevant statistics over a 10 year period. Note that the growth in California's customers and annual retail energy sales grew at a very moderate pace of 1.1 percent per year over the 10 year period.

Table 2-2
California Statistics
1990 and 2000

	1990	2000	Percent Change
Total Number of Retail Customers	12,067,907	13,078,295	8.4%
Total Retail Sales (MWh)	228,038,000	264,429,000	16.0%
Total $ for Retail Sales ($Millions in 98 dollars)	$20,214	$20,439	1.1%

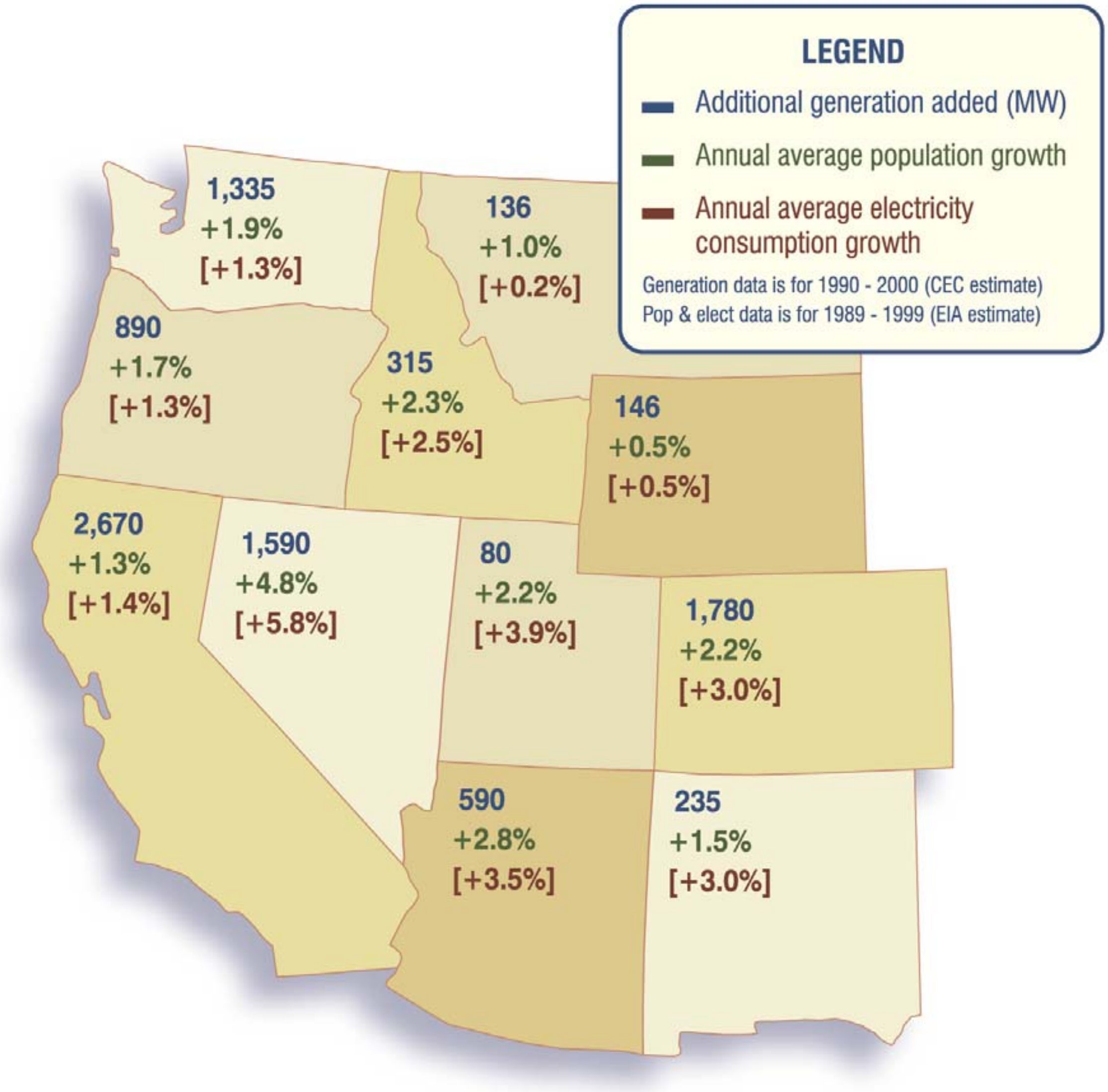
Myth: California Has Not Kept Up With the West

Another myth has been that California lagged behind other Western states in the building of new generation in the 1990s. However California has added a number of new small-sized generation facilities. In fact, in comparison to the other Western states, California added the most capacity during that term as shown in **Figure 2-10**.

While California and the West have been adding generation, population has also increased. **Figure 2-10** shows the increase in population for the Western States. Note that while California has had significant increases in population during the ten-year period, the growth in electricity demand is far less than population growth. As discussed in Chapter 5 of this report, California is in fact highly energy efficient.

The real problem is that while California has enjoyed the benefits of imports from the other regions for many years, those benefits have diminished lately. While the Pacific Northwest had surplus hydroelectricity and the Desert Southwest had surplus nuclear and coal capacity, California was able to import sufficient quantities of power to displace and augment in-state power plants. However, the other regions saw their surpluses dwindle and, as shown in **Figure 2-10**, did not continue adding generation.

Figure 2-10
Population and Electricity Demand Growth*
1990-2000



Conclusion

California has a vast array of generation and transmission facilities that serves the needs of 13 million customers. California, although consuming a great amount of energy, is actually quite efficient on a per capita basis. Some of the public characterizations regarding the summer of 2000 were found to be not true:

- California's annual electricity usage growth was not unexpected;
- California's 2000 peak electricity demand was actually less than predicted and was certainly less than the preceding year; and
- California had actually built more generation than the other Western states.

California, while relying upon a large in-state mix of diverse generation, still needs to import energy from surrounding regions. To accomplish this, an extensive network of extra high voltage transmission lines was developed to access the other regions in the West. However, the abundant surpluses that were available in other Western states are declining. There are many new generation projects under development throughout the West that may support continued trade opportunities for the near future.

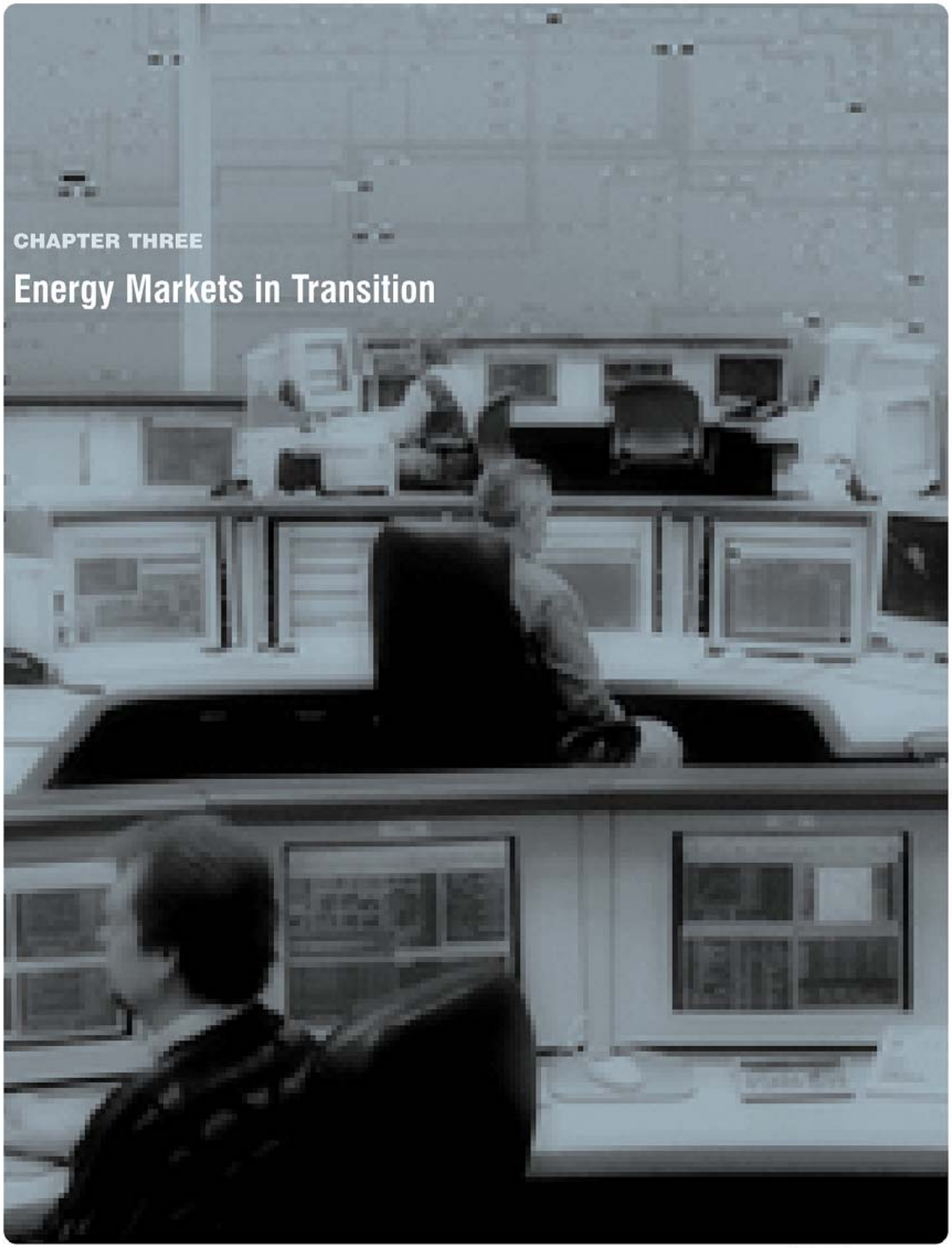


Photo: Don Saterly

Chapter 3
Energy Markets in Transition

The electricity and natural gas industries were transformed from a tightly regulated monopoly structure to a more scaled back system of enterprises guided by principles of market competition. However, the electricity market's transition towards competition is now jeopardized by consequences that were not anticipated. Contrary to original expectations, the restructured electricity market has numerous problems that compromise competition and induce serious near-term reliability risks. Consequently, California's electricity market went through severe and volatile price fluctuations during 2000 and 2001, which brought about a public outcry for change. As a result, monitoring trends in the electricity market and understanding these implications has become a more important element of Energy Commission assessment responsibilities.

Chapter 3 summarizes recent developments in the California electricity market. This chapter includes a general overview of the price volatility in the wholesale power market, the decline in system reliability, and retail price developments. This chapter sets the stage for understanding the current electricity problems.

Electricity Market Developments

In 1996, AB 1890 restructured California's electricity industry, creating a market-based system for electricity pricing and consumer choice. Although problems were encountered from the beginning, the market evolved during the first two years of the transition period and market prices appeared to track according to expectations. Wholesale electricity prices averaged $33 per megawatt-hour, which was close to the marginal cost of power production. The new structure seemed to be working, however, the summer of 2000 tested California's electric system infrastructure and the new market institutions were found wanting.

The market trends over the past year have raised serious questions about the ability of the market structure to provide affordable and reliable electricity supplies for California's residents and businesses. Electricity market problems include:

- Extremely high electricity costs,
- Decreased reliability,
- Very high profits by generators and wholesale power sellers,
- Large debt incurred by utility distribution companies on behalf of retail customers, and
- Large amounts of revenue flowing from California consumers to a few sellers.

These consequences were in part due to flaws in market design and rules.[1] The California Independent System Operator has been working with stakeholders to resolve a number of market design problems. The Federal Energy Regulatory Commission has also imposed a number of changes to the market structure to mitigate price and reliability problems. These structural changes, together with the negotiation of new long-term contracts, increased electricity generation facility construction, mandated efficiency programs and reduced energy consumption patterns have moderated the market volatility that occurred this past year.

California cannot afford the level of wholesale (and ultimately retail) electricity costs experienced over the past year for a commodity so important to the health, safety and welfare of its citizens and economy. These high prices and declining reliability due to market problems pose unacceptable costs and risks to California, the Independent System Operator, and the rest of the interconnected Western electricity system.

System Reliability

There are two components of reliability for the bulk power electric system: security and adequacy. Security relates to the ability of the bulk power electric system to withstand disturbances. A transmission system is "secure" if it can continue to provide enough power to meet demand should a disturbance occur, such as the unanticipated loss of a transmission line or generator. Adequacy implies sufficient generating and transmission capacity to meet the demands of customers. The bulk power system is "adequate" if there are sufficient generation and transmission resources available to meet projected needs at all times, including peak conditions and reserves for contingencies.

The first indication of trouble in the 2000 electricity market was a decline in electricity system reliability. The ISO dramatically increased the number of public warnings and emergency declarations in 2000 and early 2001 compared to 1998 and 1999.

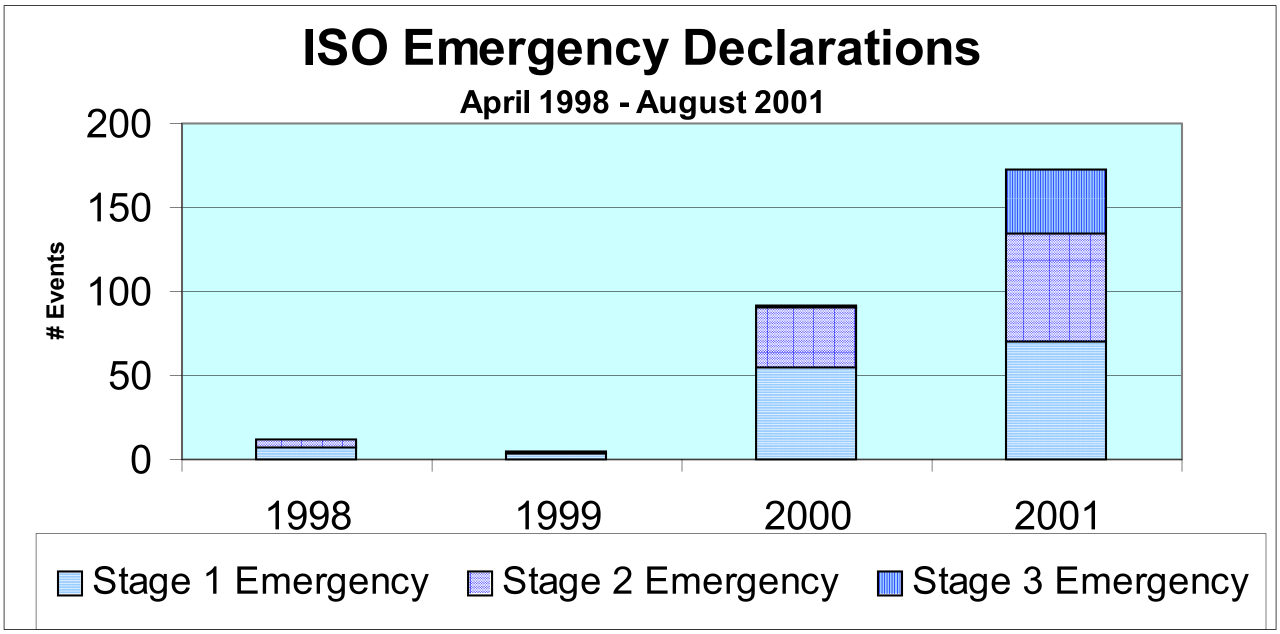
As conditions worsen, the ISO moves from Public Warning Notice[2] through a Stage 1 Emergency (operating reserves falling below 7 percent), to Stage 2 Emergency (operating reserves falling below 5 percent) and finally to a Stage 3 declaration. At a Stage 3 Emergency, reserves are falling below 1.5 percent, system collapse is imminent and firm load may be shed. **Figure 3-1** provides a summary of ISO system emergencies. Nearly 85 percent of the system emergencies that occurred in the first three years of operation has taken place in 2000. However, the ISO declared more emergencies during the first three months of 2001 than in the previous years.

---

[1] A number of market flaws are identified in *FERC Order Proposing Remedies for California Wholesale Electricity Markets* and *Staff Report to FERC on Western Markets and the Causes of the Summer 2000 Price Abnormalities*, November 1, 2000. See also the ISO's Market Surveillance Committee Reports dated October 18, 1999, March 9, 2000, July 6, 2000, September 6, 2000, and December 1, 2000.
[2] Public Warning Notice includes "No Touch," Alerts, Warnings and Power Watch declarations.

Calling Stage 1, 2 or 3 emergencies allowed the ISO to invoke increasingly severe load reductions, out-of-market actions and power acquisitions in their attempt to stabilize the grid. These emergencies had escalating impacts on generator performance and market bidding, so they became a market management tool as well as a traditional emergency response system. This dual role became even more apparent in the almost non-stop Stage 3 emergencies that characterized January and February 2001.

Figure 3-1



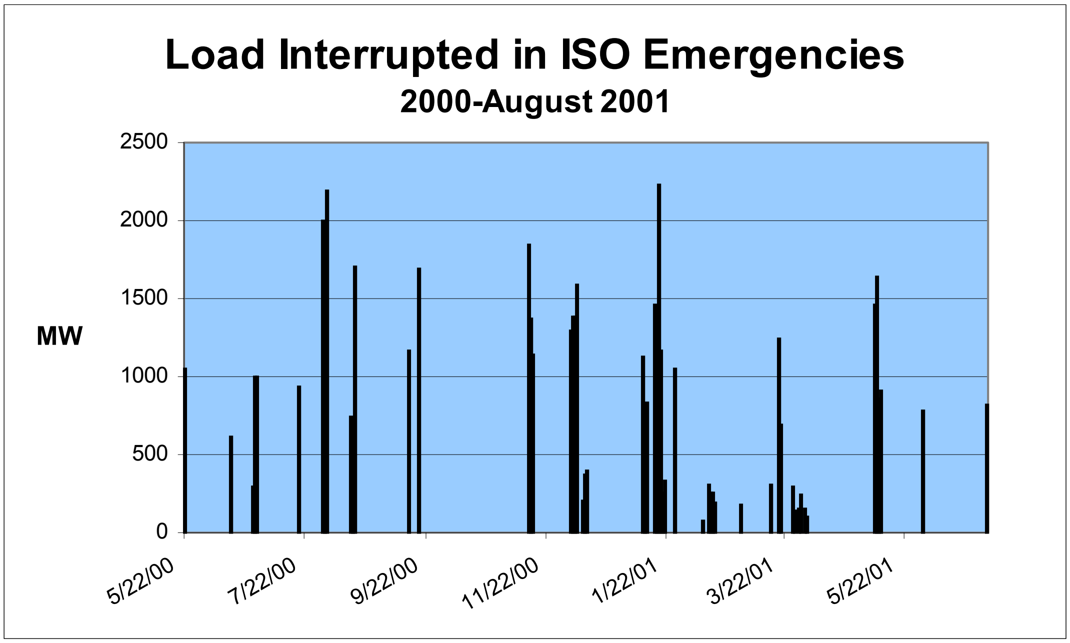
Source: California Independent System Operator, [http://www,caiso.com/docs/2001/06/01/200106011245292801.xls]

Rotating outages are ordered when the system is in danger of collapse and some load must be shed to preserve the rest of the system. On May 22, 2000, the ISO's first outage curtailed several hundred large PG&E customers. The second outage occurred on June 14 with nearly 95,000 residential and small commercial Bay Area customers that were curtailed. The May outage was caused by a coordination problem. The ISO called for customer curtailment because it made a calculation error that overlooked 1,500 MW of capacity in reserve. Transmission system limitations, coupled with record area loads and limited local generation, resulted in the June 14 outage. Fortunately, despite the many Stage 2 emergencies that plagued the rest of 2000, no further rotating outages occurred until December 7, 2000.

Not all system crises are as catastrophic as rotating outages. In a Stage 2 emergency, the ISO can contract for higher cost power and interrupt customers who had contracts that traded a lower energy price for the right to be interrupted. This clause had rarely been invoked until the summer of 2000.

The ISO called on firm and interruptible customers to reduce demand 24 times in 2000, compared to 4 times in 1998 and once in 1999. By comparison, firm and interruptible customers were curtailed 31 times in the fist half of 2001. Between 400 MW and 2,190 MW of customer demand were interrupted during these periods, as shown in **Figure 3-2**. The frequency and duration of these interruptions became a major problem in customer acceptance of the market's performance.

Figure 3-2



Source: California Independent System Operator, [http://www,caiso.com/docs/2001/06/01/200106011245292801.xls]

Most emergencies were the result of insufficient scheduled generation. There were many occasions during the summer when the ISO was able to procure sufficient generation at the last minute to keep from curtailing customers. The problem did not stem from unexpected hot weather; peak demand was actually lower than the two previous years (1998 and 1999). It appears that there was a sufficient number of generation capacity available to meet load during the summer of 2001. However, the generators were submitting bids among the different PX and ISO markets and scheduling exports in such a manner that the ISO recorded low operating reserves. Reliance on the spot market brought daily uncertainty to the system operators. This type of uncertainty was unknown under the regulated market, because the utility operators had full control and discretion of their generation facilities to meet expected demand. Chapter 4 will cover this subject in greater detail.

Market developments shifted after the summer 2000 peak season, bringing a different set of problems that forced the ISO to declare emergencies throughout the rest of the year. Although there was sufficient generation capacity to meet peak demand, the gas-fired facilities had to run harder and longer over the summer period. Preliminary statewide electricity consumption estimates for 2000 show that electricity use increased by about 4.5 percent. **Figure 3-3** shows the ISO monthly loads (about 80 percent of total statewide demand) for 1999 and 2000. Most of the increases in the ISO region occurred during the summer when temperatures where higher than normal.

As **Figure 3-4** shows, California hydroelectric generation (including Hoover Entitlements) was higher than average and almost equal to 1999 levels. California had an unusual water year that affected hydro generation, since snowmelt came later in the season. However, imports did decline in comparison. The California gas-fired generation facilities were able to make-up the difference and satisfy the increased demand.

Consequently, many of these generation facilities that ran at high capacity factors in the summer were being shut down for either planned or forced maintenance in the fall. Unfortunately, there is no longer a coordinated effort to plan for maintenance outages and California was confronted with large facility outages that continued throughout the end of the year. The California Public Utilities Commission attempted to verify the cause of many of these maintenance outages. **Table 3-2** shows that the facility outages in the ISO and statewide region were significantly higher than the previous year.

Figure 3-3
California ISO Electricity Load

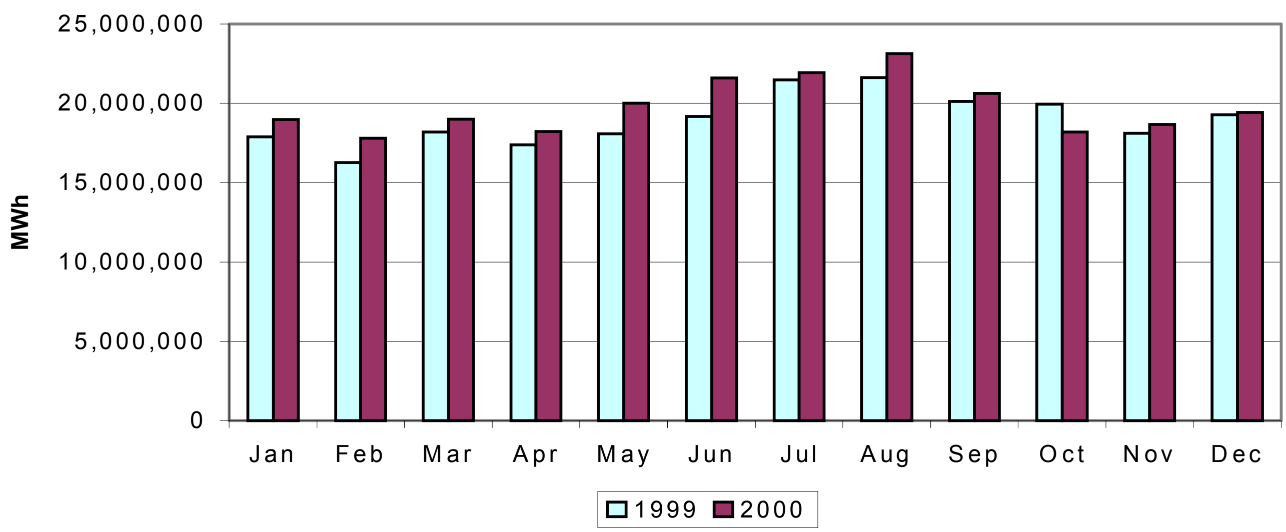
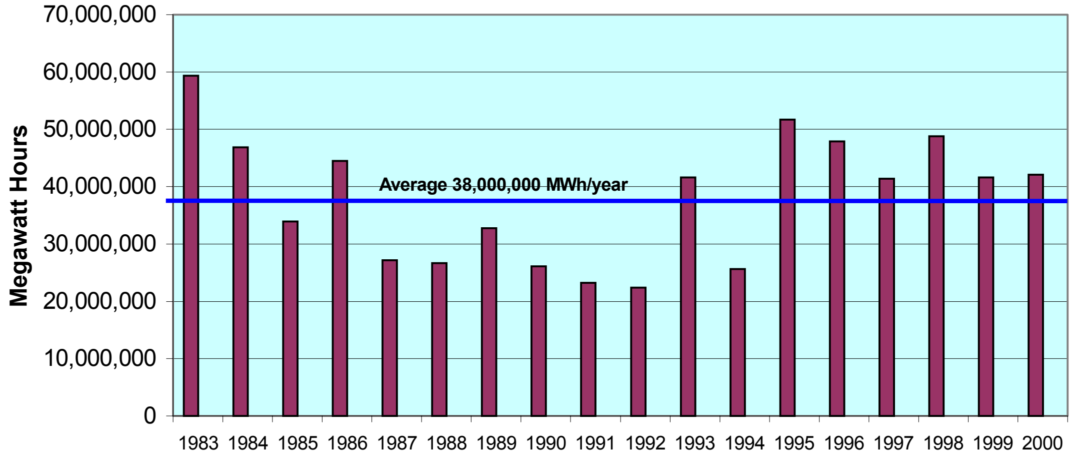


Figure 3-4
California Hydroelectric Generation
Include California's Hoover Entitlements



Source: California Energy Commission

Wholesale Price Increases

In addition to reliability failures, stresses on the ISO electricity markets are evident in the increasing cost of serving ISO load. California's electricity market experienced severe and volatile price fluctuations during the summer of 2000 and escalated even further into the winter. In the June through September period, California spent over $13 billion on electricity in the wholesale electricity markets run by the ISO and PX, more than what was spent in the entire one-year period of 1999.

Wholesale electricity cost the ISO's customers $27.1 billion in 2000, more than triple the amount spent during 1999 ($7.4 billion) and five times 1998 expenditures ($5.5 billion)[3]. The estimates include the costs for PX energy, bilateral contracts, real time purchases and ancillary service requirements; these estimates do not include any additional costs that other California municipal utilities incurred over the period. **Figure 3-5** shows the average monthly wholesale costs incurred in 1998 through the first half of 2001.

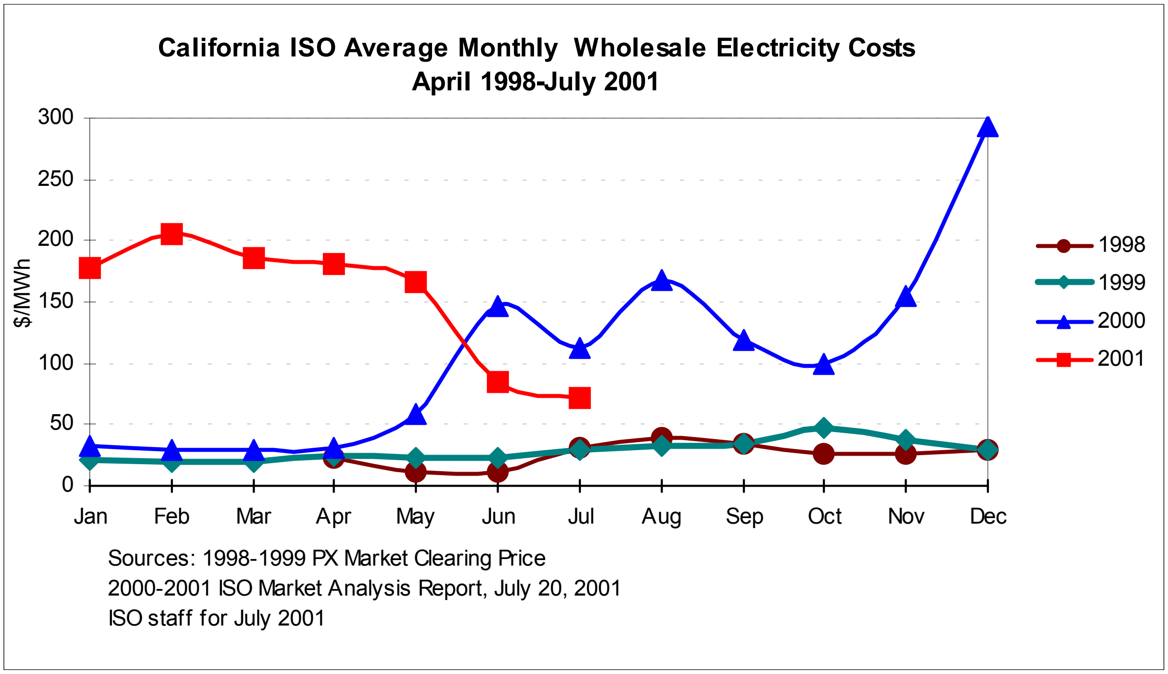
[3] Anjali Sheffrin, ISO Market Analysis Report, January 16, 2001.

Table 3-3
ISO and Statewide Generation Outages

	CAISO		State	
Month	**Outages (MW)**	**Percent of Forecasted Peak**	**Outages (MW)**	**Percent of Forecasted Peak**
1999				
Jan	2,124	7%	3,068	10%
Feb	3,828	13%	5,096	17%
Mar	3,979	14%	5,740	20%
Apr	4,694	17%	5,739	20%
May	2,368	8%	3,032	11%
Jun	967	2%	1,216	3%
Jul	876	2%	963	3%
Aug	834	2%	878	3%
Sep	1,172	3%	1,195	3%
Oct	1,153	4%	1,761	5%
Nov	1,985	7%	2,988	10%
Dec	1,806	6%	2,569	8%
2000				
Jan	1,720	6%	2,423	8%
Feb	2,174	7%	3,243	11%
Mar	2,156	7%	3,389	11%
Apr	2,179	7%	3,329	11%
May	2,963	9%	4,012	13%
Jun	2,011	5%	2,683	7%
Jul	1,915	5%	2,233	6%
Aug	2,179	5%	2,434	6%
Sep	3,409	10%	3,621	10%
Oct	7,206	23%	7,633	25%
Nov	9,754	31%	10,343	33%
Dec	8,039	25%	8,988	28%
2001				
Jan	8,807	29%	9,940	32%
Feb**	9,111	31%	10,895	37%
Mar	10,558	37%	13,737	48%
Apr	12,164	44%	14,911	54%
May	11,787	38%	13,431	37%
June	5,404	17%	6,794	18%
July	3,941	12%	5,044	13%
August	3,369	9%	4,229	10%

*Includes both forced and planned outages

Figure 3-5
CAISO Wholesale Electricity Costs
($ per MWh)



Spot market energy costs increased dramatically beginning June 2000. This trend first occurred when there were system stability problems in the San Francisco Bay Area. As overall prices increased, the total electricity cost for December ($6.2 billion) was 52 percent more than the cost for August ($4.2 billion or $180 per MWh), the month electricity demand was highest. The ISO ancillary service and real-time energy costs also showed an upward trend, increasing 750 percent over 1999 costs. This was significant since ancillary costs were expected to remain small, and the increase in real time energy demonstrated the high costs to balance under-scheduled generation bids.

Wholesale price increases were based in part on high natural gas prices and increased demand in adjoining states that likely resulted in higher priced energy imports. Natural gas prices in the summer of 2000 were 80 percent higher than in the summer of 1999, and fuel 55 percent of the generation that typically meets ISO load. However, the increased natural gas price does not explain the increase in electricity prices. If California wholesale prices were cost-based, an 80 percent increase in natural gas prices would result in only a 44 percent increase in prices to meet ISO loads[4].

[4] Using the system average heat rate of 10,000 Btu/kWh for gas units serving ISO loads.

Electricity costs finally began to decline during the summer of 2001. Electricity costs declined due to a number of factors, including:

- Natural gas price returned to normal levels,
- DWR firm power purchases reduced the reliance and volatility of the spot market,
- Temporary price limits to price spikes imposed by the Federal Energy Regulatory Commission due to the lack of market competition, and
- Reduced consumption of electricity due to moderate temperatures and consumer conservation initiatives.

Air Emission Cost Effects on Electricity Prices

The market value of nitrogen oxides (NO_x) air emission credits necessary to operate existing California power plants in Southern California went from $2 per pound to nearly $50 per pound in 2000. Each electric generator participating in the South Coast Air Quality Management District (SCAQMD) Regional Clean Air Incentives Market (RECLAIM) was required to have NO_x emission credits to off-set their emissions.

A generator in SCAQMD is allocated a number of credits each year. The generator needed to purchase additional credits if their allocations were used as offsets or traded. This is the only air quality management district in California that has a NO_x trading system. All other California generators do not need to purchase NO_x credits.

Generators generally added the cost of these RECLAIM credits to their fuel expenditures to determine their operating cost. These generators also added the market value of their original RECLAIM allocations to the total cost claims.[5] The generator considers the market value of these allowances as an opportunity cost, assuming that they are giving up the chance to sell allowances at a profit.

In the uniform price auction of the ISO and PX, the highest cost-winning bid sets the price for scheduled generation for that period. If all electric generators bid their operating costs and a generator paying for NO_x credits in Southern California is the highest cost-winning bid, then all scheduled generation is paid a price that includes the cost of the NO_x emission credits. This is true even if the bidder is a hydroelectric power plant operator in the Pacific Northwest, a coal plant in the southwest or a gas-fired power plant in Northern California.

In the high-demand summer months, the generators buying NO_x emission credits may have had the highest operating costs in many hours and set the price for all power bought by the ISO and PX. The cost of NO_x emission credits on the uniform price auction added roughly $500 million to $2 billion to the cost of power in the summer of 2000. PG&E, SCE and SDG&E incurred millions of dollars in wholesale power costs daily from generators who do not pay these costs, but who benefit from the workings of the single price auction.

[5] SCAQMD Rule 2007(e): District RTC allocations are always without cost to the facilities.

The high demand and price of emission credits in Southern California contributed to a portion of the high energy bids and energy market clearing prices experienced during the summer of 2000.[6] [7] In early 2001, SCAQMD acted to de-couple emission credit prices from wholesale energy market prices by removing the generators from the RECLAIM program for a three year period. During this time, generators who exceed their emission allowances will pay a set registration fee of $7.50/lbs of NO_x, removing the incentive to bid up the price of NO_x credits. Furthermore, generators have applied for permits to install NOx emission control retrofits on most power plants in the South Coast Air Basin. Once controls are installed, the demand for emission credits should stabilize, as should their price. Given these changes, emission credits prices should fall to historical levels and remain at those levels when generators are returned to the RECLAIM program.

Retail Price Developments

Most retail customers did not see the high wholesale costs reflected in their monthly bills. Customers of the investor-owned utilities (IOUs) had their rates frozen as part of the overall legislative design for restructuring. This arrangement changed briefly for San Diego Gas and Electric customers during the summer, until AB 265 established a $0.065 per kilowatt hour (kWh) cap on the wholesale rate that is allowed to be passed along to residential, small commercial and street-lighting customers. There were also rate hikes during the early months of 2001; first with a 1 cent per kWh temporary increase and then larger increases established in April 2001.

Roughly 40 percent of the revenues derived from frozen rates were set aside to pay for the wholesale cost of energy. The rest of the revenues went to: transmission, distribution, public purpose programs, the competition transition charge, the trust transfer amount for the rate reduction bond, nuclear decommissioning, ancillary services, system operation and other miscellaneous charges. **Figure 3-6** shows typical IOU residential charges for electricity[8]. The cost for generation could vary significantly over short periods of time since the price of electricity changes in wholesale markets. Other costs, such as transmission and distribution charges, change gradually as depreciation accrues or new facilities are added.

Figure 1-7 shows average electricity costs to residential customers of SDG&E, Edison, PG&E, Los Angeles Department of Water and Power (LADWP) and Sacramento Municipal Utility District (SMUD). During this period, municipal utilities also kept their rates at constant levels. However, some municipal utilities needed to purchase power from the spot market and incurred larger costs than expected. For example, SMUD bought approximately 35 percent of its power needs from the open market and cost the utility $68 million more than

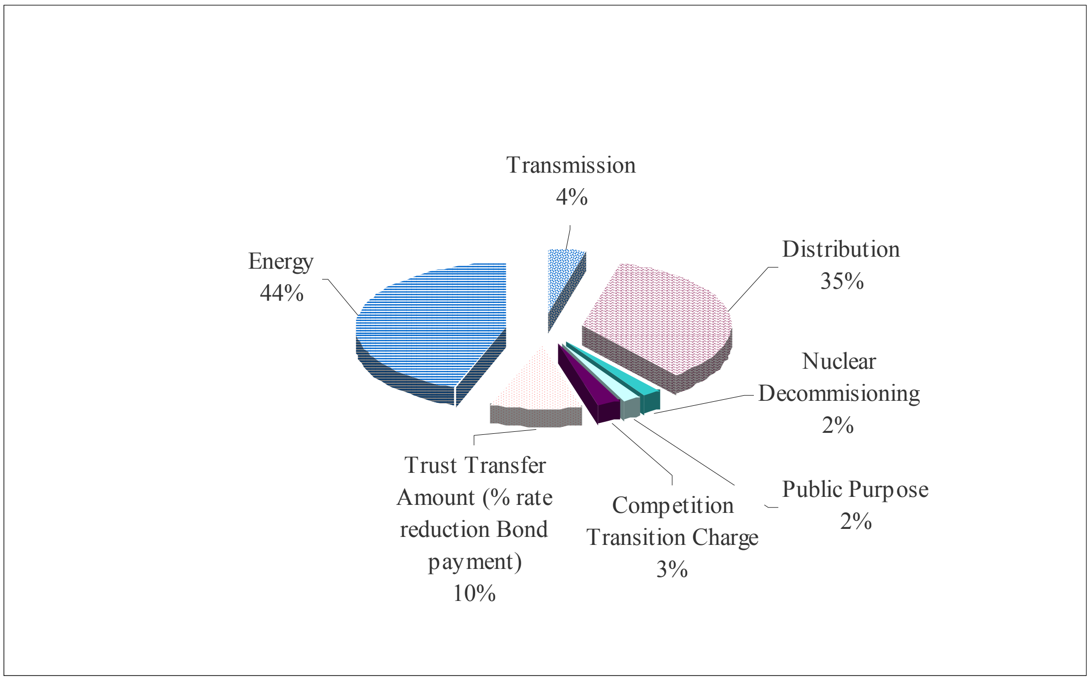
---

[6] Scheible, pages 5-6.
[7] Joskow, Paul, and Edward Kahn, A Quantitative Analysis of Pricing Behavior in California's Wholesale Electricity Market During Summer of 2000, November 21, 2000, page 2.
[8] Links to utility websites that describe the components of customer electricity bills can be found at: [http://www.consumerenergycenter.org/homeand work/homes/youbill/understand.html]

expected, severely draining the utility's rate stabilization fund accumulated since 1997. For LADWP, which has more generation capacity than necessary from numerous plants and long-term contracts, higher prices have generated millions in extra revenues from excess sales.

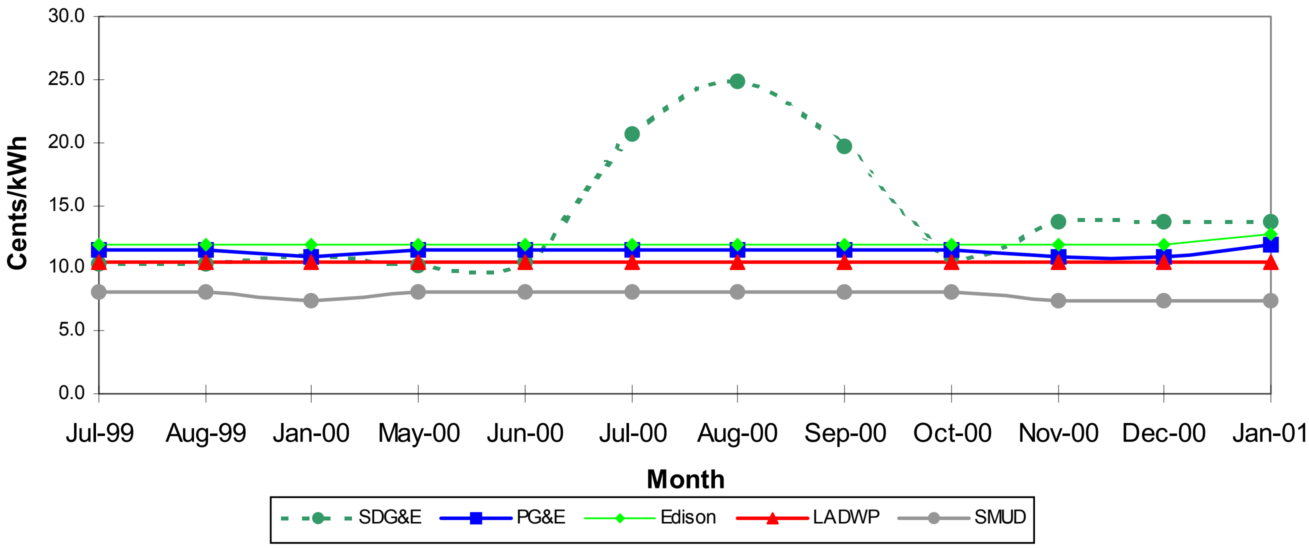
The total bill impact of the changing retail electricity rates is shown in **Table 3-3**. The bulk of the increase in industrial-customer retail electricity costs is attributable to San Diego's pass-through of the high electricity costs during the summer of 2000. This pass-through increased retail rates for the typical SDG&E industrial customer by 197 percent. However, utility rates do not necessarily reflect what the bulk of industrial customers are paying for retail electricity. It is often held that industrial customers do not need regulatory protections because they are more likely to bypass the regulated utility and utilize sophisticated electricity purchasing and hedging practices.

Figure 3-6
Typical IOU Residential
Percentage Charges with Frozen Rates



Source: Energy Commission Staff

Figure 3-7
Average Residential Electricity Costs



Source: California Energy Commission

Table 3-3
Retail Electricity Bills for Typical Customers
Summer Months in 1999 and 2000
California ISO Control Area
$ Nominal

	Residential	Small Commercial	Medium Commercial	Industrial	Agricultural
1999	$55.67	$156.09	$2,362.29	$61,998.94	$597.23
2000	$57.49	$163.66	$2,420.71	$75,770.79	$658.30
Increase	$ 1.81	$ 7.58	$ 58.41	$13,771.85	$ 61.07

Source:

Although electricity rates for customers of most IOUs and municipal utilities have not increased, SDG&E customers felt in full the brunt of the rates during the summer 2000. For example, Fletcher Hills Farms, a small dairy store in business for 30 years in El Cajon saw its electricity bill jump from $1,000 a month to just under $3,000. The store owners made the decision to close the business. Venice Pizza, a small family-owned operation in Normal Heights, increased the price of pizza by 50 cents to recoup the increase in their electricity bill from $1,100 to $2,350. Similar cases might occur all over California once Edison and PG&E terminate their rate freeze. Rates for these utilities will reflect the high cost of obtaining energy. Most likely, municipal utilities will also adjust their own rates to remain competitive with the IOUs.

Utility Financial Crisis

Under California's electricity restructuring law and California Public Utilities Commission Decisions, the investor-owned utility (PG&E, Edison and SDG&E) electricity rates were frozen at June 10, 1996 levels. The rate freeze ends March 31, 2002, or sooner if the utilities collect enough excess revenue from rates and power plant sales to accelerate recovery of their uneconomic assets. Although the rate freeze did not apply to municipal utilities, these publicly-owned utilities also froze rates for their customers.

For two-and-a-half years, the IOUs collected enough revenue to cover their requirements, plus some excess revenue for the recovery of uneconomic costs. Through this mechanism, SDG&E was able to collect enough revenue to fully recover its uneconomic assets. Hence, on June 30, 1999, the California Public Utilities Commission (CPUC) allowed SDG&E to lift the rate freeze for its customers.

PG&E and Edison, on the other hand, continued collecting excess revenues. However, during the summer of 2000, the electricity that the utilities purchased in the Power Exchange (PX) doubled and then even tripled in price. Because of the rate freeze, the utilities could not pass these expenses to their customers, leaving PG&E and Edison with negative balances in their revenue accounts, as indicated in **Table 3-4**. In order to deal with some of the IOU deficits, the CPUC approved a temporary (three-month) one-cent energy rate increase to all IOU customers in January 2000. This increase denotes an overall rate increase of nine percent for residential customers and more than ten percent for the remaining customer classes.

This rate increase provided PG&E an additional $80 million dollars per month, which PG&E considered insufficient to erase the $6.4 billion dollars revenue deficit accumulated trough March 2001. PG&E declared bankruptcy on April 6, 2001.

Although Edison is in the same situation as PG&E with a revenue deficit approaching $6.6 billion dollars, the utility has been negotiating with Governor Davis to solve its problems without declaring bankruptcy. The State Legislature also passed a law (AB 265) in August 2000 that freezes energy charges at 6.5 cents per kilowatt-hour for residential and small commercial customers of SDG&E. The effects of the law were retroactive to June 1, 2000. Because energy collections from customers are frozen, SDG&E has accumulated over a billion dollars in energy undercollections.

Causes of Market Problems

During the debate about the cause of California's electricity problems, some have argued that price volatility is an inevitable characteristic of markets run by the ISO and PX. Some contend that high prices experienced in electricity markets in 2000 are not a totally unexpected phenomenon. It is true that periods of price spikes and supply shortages are common in commodity markets, particularly in markets like electricity that require significant capital investments. On the other hand, collapsing prices and excess supplies have historically been common in such markets as well.

Commodity markets use high prices to induce investments in new production capacity. Generally speaking, rising prices from shortages of capacity encourage the construction of new power plants and/or expansion of existing facilities. In most markets, as these additional resources come on-line, prices tend to decline. As a consequence, idle capacity may lead to temporary plant shutdowns, and investors planning to construct new facilities may defer those plans to await higher prices.

Table 3-4
IOU Revenue Collection Deficits
Estimated through March 2001
$MM

Customer Classes	PG&E	SCE	SDG&E
Residential	$ (1,591)	$ (971)	$ (393)
Small Commercial	$ (552)	$ (585)	$ (237)
Medium Commercial	$ (541)	$ (569)	$ (235)
Industrial	$ (1,480)	$ (992)	n/a
Agricultural	$ (168)	$ (654)	n/a
Total	**$ (4,332)**	**$ (3,772)**	**$ (865)**

Note: This table reflects an estimate of revenue undercollections due to high wholesale energy prices in the market from June 2000 to July 2001. Staff did not take into account revenue collections from competition transition charges before June 2000. Staff did not estimate the differences between generation charge in the rates and revenue requirement of Utility Retained Generation.

However, the electricity market may be inherently different from other commodity markets due to the physical reality that coordination of the system is absolutely critical.[9] In addition, the demand for electricity is highly variable due to the weather changes, which can exacerbate the cyclic nature described above. Another distinguishing characteristic of electricity markets is the limited ability to store, or stockpile the product. Large inventories help other markets control exposure to wide price swings.

Notwithstanding the nature of commodity markets, many entities – including the California Public Utilities Commission (CPUC), the Electricity Oversight Board (EOB), the Federal Energy Regulatory Commission and the ISO's Market Surveillance Committee (MSC) –

[9] *Electricity Market Reform in California*, John D. Chandley, Scott M. Harvey, and William W. Hogan, November 22, 2000 provides the following description of the need for system coordination: "Over short horizons of a day or less, generating facilities must work through the transmission network to provide the multiple products of energy, reserves and ancillary services. These same generating facilities must provide all of these products, in the right amounts, and with very limited tolerances."

have concluded that flaws in market design and rules are a major factor in the excessively high prices for electricity. Weather conditions, tight supplies, increased costs of natural gas and high emission credit prices also contributed to higher costs for electricity this summer. However, these factors do not adequately explain the levels of prices seen in the ISO and PX markets from the summer of 2000 to present. Some of the major flaws in the market structure and rules that have been identified include:

- Sole reliance on the PX spot market to meet demand and balance reliability needs,
- Exercise of market power to raise wholesale electricity costs,
- Lack of demand responsiveness,
- Out-of-market purchases above price caps,
- Limited ability of the utilities to use forward contracts,
- Conflicts of interest for the ISO Stakeholder Board, and
- Unintended consequences of RECLAIM on the electricity market.

The Legislature's intent was that restructuring of the electric industry should enhance the reliability of the state's bulk power electric system. Maintaining the flow of electricity through the vast network of transmission lines that run the length of California and connect our market with that of neighboring states is a complicated, technically sophisticated matter, which has required the voluntary cooperation of all network participants. The governing structure for ensuring reliability in the past relied largely on the voluntary actions of the utilities and market stakeholders. Restructuring has compromised that voluntary system of ensuring reliability by placing once cooperative entities into direct competition with one another. This system for ensuring reliability is unraveling under the pressure of competition.

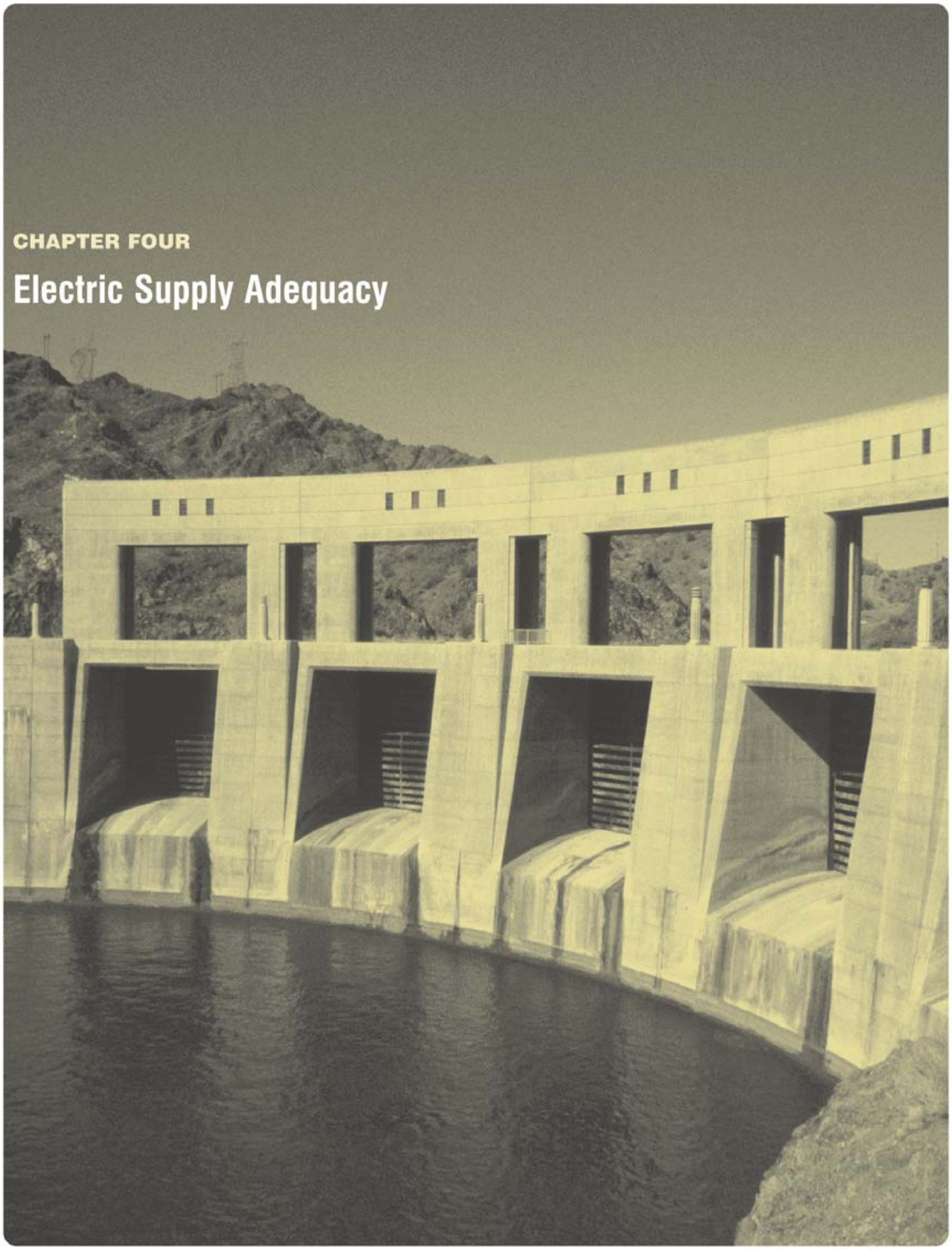


Photo: Department of Water Resources

Chapter 4

Electricity Generation Supply Trends

This chapter looks at electricity generation supply trends from this past summer and provides an assessment of the expected demand/supply balance for the summers of 2002 through 2004. After 2002, the supply picture becomes more uncertain. While several thousand megawatts of new power plant capacity that are under construction in the state, even more are currently under review in the Commission's siting process. Once the Commission approves these applications for new power plants, the owners of the plant may decide not to proceed immediately with construction for a number of reasons. These reasons may include unresolved market structure and pricing issues, constraints within the state's natural gas pipeline and transmission line network, or the presence of too much generation capacity which could depress prices below the level needed by new generators to recover their revenue requirement.

Electricity Market Concerns

Given the electricity market crisis of the winter of 2001, a future where excess power plant capacity depresses prices may seem improbable. However, in regions such as Texas and the Northeast, new power plant additions are expected to increase supply by at least 25 percent against an estimated demand growth of less than 5 percent. Because of the transmission constraints in these regions, the ability to move the output of these new power plants to other parts of the country is limited. In these regions, oversupply will likely translate into lower prices for consumers, but generators might also have to bear lower returns on their new investments.[1]

Generally, most capital intensive industries experience periodic cycles of excess and under production capacity.[2] The problem this represents for the electric generation sector is that by the time the market sends appropriate signals that capacity is insufficient, system reliability is severely compromised and there is extreme price volatility. Furthermore, the collapse of the California Power Exchange (PX) has complicated the picture with respect to where transparent pricing signals will come from to incent the construction of new generation. All previous Commission staff analyses of future market prices and incentives for new construction have been based on expected market clearing prices from the PX.

For the next 5 to 10 years the California electricity market appears to be one that will be dominated by bilateral arrangements where large industrial users and the Department of Water Resources negotiate long-term contracts directly with generators. In terms of

---

[1] RDI Consulting, "Identifying the Booms and Busts: An Assessment of Cyclical Trends in the U.S. Power Supply Business," September 2000.
[2] See Staff technical Studies in Boom-Bust cycles at: HTTP://WWW.ENERGY.CA.GOV/REPORTS 2000-300-00-001.HTML.

providing both revenue security for generators and supply certainty for consumers, this is a superior outcome compared to relying on vagaries of the PX spot market. With respect to the issue of ensuring that adequate supplies of electricity exist, there clearly is an ongoing need for periodic assessments of supply adequacy not only for the state, but also for the entire interconnected western region. In the absence of transparent pricing signals to incent the construction of new generation, a process that identifies future need for new generation or conservation and establishes a competitive system to meet that need will have to be implemented.

Supply Adequacy Outlook

It is difficult to accurately assess the supply adequacy picture for California because of changes brought about by deregulation. Most of the existing power plants once owned by California's three investor-owned utilities were sold and the owners of these plants, plus those of the new plants that will be built in California, have no obligation to serve load in the state. Restructuring has "regionalized" the generation market in California allowing generators to sell to the highest bidder. That bidder can be in California, in Nevada, or any other western state that is facing a generation supply crunch and growing electricity demand. Therefore, a simple counting of megawatts of generation capacity in the State provides an incomplete picture of supply adequacy. An examination of how California's competitive electric generation market performed this past summer provides useful insight into how market dynamics and market rules—especially prices caps—affect supply adequacy.

Summer of 2000

On May 10, 2000, the California ISO issued their assessment of supply adequacy for the coming summer. Despite a surging demand for power fueled by California's robust economy and a narrowing of the supply margins needed for operating reserves, the ISO was confident that enough electricity would be available to ensure reliability during the summer. Less than two weeks after the ISO issued their forecast, the state and the rest of the west was hit with unseasonably warm weather. There was also an outage of nearly 6,000 MW of generation capacity. The combination of these two events resulted in the ISO declaring a stage two emergency. [3] This emergency in May turned out to be an omen for the summer. By the end of the year, the ISO had declared a total of 55 stage one emergencies, 36 stage two emergencies, curtailed interruptible load customers on 23 days and had 1 stage three emergency.

[3] A stage two emergency signals that operating reserves, the margin of excess generation capacity over load, have fallen below 5 percent. Under a stage two emergency, the ISO requests that the utility distribution companies notify their interruptible load tariff customers to curtail their operations in order for the ISO to maintain at least a 5 percent reserve.

Given the number of emergencies declared, was the ISO's assessment about supply adequacy for the summer of 2000 unrealistic? Based on their experience from the previous two summers, the ISO had reason to be cautiously optimistic. The state had survived the summer 1998 and 1999 with only five stage 2 emergencies being called.

Temperatures in the state and throughout the entire west during the summer of 1998 were the hottest over the last 40 years—both in terms of actual temperatures and the number of hot days over similar periods. However, hydro availability during the summer was exceptionally good because of heavy rainfall and snow throughout the preceding winter and spring. In contrast, the summer of 1999 in California turned out to be one of the coolest on record based on the number of moderate temperature days. Although the summer average temperature was cool, an intense heat wave that occurred over a couple of days in July resulted in a peak demand that was even higher than the 1998 peak.

It turns out that the summer of 2000 was warmer than average with temperatures equaling the 10th hottest summer on record. However, peak demand was lower than the 1998 and 1999 peaks. **Table 4-1** shows the reported ISO peak demand and reserve levels over the last 3 years.

Table 4-1
California ISO Peak Demand

Year	Peak Demand*	Reserve Levels at Peak Time
1998	45,676 MW	Below 5%
1999	45,884 MW	Above 5% below 7%
2000	45,494 MW	Below 5%

* Peak demand includes interruptible load called.

Despite all of the emergencies that occurred during the summer of 2000, the ISO was able to reliably provide electricity to meet all of the firm load throughout the summer by purchasing significant amounts of electricity at the last moment. These last minute purchases are referred to as Out-Of-Market (OOM) calls. OOM calls are made in response to general system shortages and to relieve intra-zonal congestion after all available PX and ISO markets for energy are exhausted.

The ISO reports OOM purchases as imports, but that does not necessarily mean that the energy is coming from plants located outside of the ISO control area. According to three separate reports—issued by the Compliance Unit of the California Power Exchange (PX), the Market Analysis staff of the ISO, and the staff of the FERC[4]—the presence of price caps on

[4] *Price Movements in California Electricity Markets*, California Power Exchange Corporation Compliance Unit (PX September report), September 29,2000; *Report on California Energy Market Issues and Performance: May-June, 2000,* California Independent System Operator, Department of Market Analysis, August 10, 2000;

the ISO's markets and the lack of price caps on OOM purchases combined to incent generators within the state to use exports as a means of manipulating the market. A generator located within the ISO control area could avoid the appearance of withholding generation from the ISO's capped markets by selling generation into day-ahead and forward markets to market traders or affiliates in surrounding control areas. Delivery would take place at a trading hub, such as Palo Verde or the California-Oregon Border, where it could be parked, and then resold to the ISO via uncapped OOM purchases. **Table 4-2** below shows that exports rose throughout the summer as price caps dropped. Initially OOM purchases also increased as price caps dropped.

Table 4-2
Exports and OOM Purchases Summer 2000

Period	Price Caps	Exports (MW)[5]	OOM Purchases Percent of Total Imports	OOM Purchases % of Real Time Imports
6/1/00-6/30/00	$750	2,995	12	26
7/1/00-8/6/00	$500	3,846	28	44
8/7/00-8/31/00	$250	4,851	17	24

Source: Market Analysis Report, Eric Hildebrandt, Manager, Market Monitoring, ISO Board Meeting, November 30, 2000.

If the capacity purchased by the ISO through OOM calls had bid into any of the PX's or ISO's capped markets, would there have been a need for the ISO to declare as many stage two emergencies as they did? The CPUC staff in their response to the FERC staff report concluded that by removing supply from the day-ahead and hour-ahead markets through exports and forcing the ISO to procure supply in real times, the perpetrators of this behavior contributed to the high incidence of emergency alerts and threatened the reliability of the system.[6] Generators and marketers have an even greater incentive to engage in this kind of behavior when the availability of excess generation capacity over demand is small. This "gaming" of the market points out that the amount of generation needed to reliably meet load is not necessarily the same amount of generation needed to promote competitive behavior.[7]

---

and *Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities*, (Section 5, Why Were Prices High This Summer?), November 1, 2000.

[5] *Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities*, (Section 5, Why Were Prices High This Summer?), November 1, 2000, p.5-6.

[6] *Analysis of FERC Order and Staff Report*, Exhibit PUC-8, Import/Export Patterns Need Further Investigation, CPUC Staff Report, November 21, 2000.

[7] Scarcity of supply may not be the only reason generators have been able to game the market to the extent seen this year. Supply of generation may be adequate, but its distribution among market players may not be sufficiently diffuse to insure competitive behavior.

Statewide Supply Adequacy vs. Local Area Reliability

Even if the supply of generation capacity is adequate from a statewide perspective, constraints within the transmission network create opportunities for generators to exert market power. This point was illustrated on June 14, 2000 when the ISO was not able to reliably serve firm load in the San Francisco Bay area and PG&E was forced to curtail its customers in that area through the use of rolling power outages.

On June 14 temperatures in the San Francisco Bay area reached the highest levels ever recorded over the last 125 years. In addition to these extreme temperatures, approximately 500 MW generating capacity in the area was unavailable due to planned maintenance and unplanned outages. Temperatures throughout the rest of the state were also high, but it was the heavy demand for electricity in the San Francisco Bay area and the lack of sufficient generation *in the region* that created a great deal of instability in the system with dropping voltage levels. Major substations that feed generation into the Bay area from other locations of the state were at their operating limits and in danger of overloading. This situation prompted the ISO to have PG&E call on all of its interruptible load customers to drop load. The ISO also requested that PG&E cut off power to firm load customers in the Bay area to prevent cascading outages throughout the rest of the State and the west. Approximately 95,000 citizens and businesses in the greater Bay Area were with out power for up to 6 hours.

The events that took place within the San Francisco Bay area on June 14 were unprecedented and would have been impossible to plan for this contingency. For such extreme contingencies, such as the 1-in-125 year temperatures combined with multiple outages of power plants, shedding of firm customer loads is a long-standing industry security procedure to protect the system from collapsing and may be the most economical solution in preventing voltage collapse.

What happened in the San Francisco Bay area shows that while statewide supplies of generation were adequate, they were clearly inadequate with respect to maintaining reliability on a local area basis. The ISO conducts annual studies to identify those areas of the State where the absence of power plants is compromising the reliability of the State's electricity system due to the transmission network constraints. These local reliability areas are shown in **Figure 4-1**. The most problematic areas of the State, with respect to a lack of local generation, are the San Francisco Bay area and San Diego.

Figure 4-1
Local Reliability Areas in California

Source: Presentation California ISO Stakeholder Meeting 3#, December 13, 2000, 2002 -2004 RMR Study Preliminary Findings Summary, Grid Planning.

Within the San Francisco Bay area, new generation is needed for the following reasons:

- Transmission capacity into the area, especially the peninsula, is limited,
- Existing power plants in the area are old (between 30 and 40 years or older) and not highly reliable, and
- Demand has been growing rapidly with the improved economy.

Transmission improvements are also needed in the San Francisco Bay area to allow for the maximum utilization of the system under peak demand conditions while avoiding overloading the various components of the network, such as a substation, which can lead to local power outages.

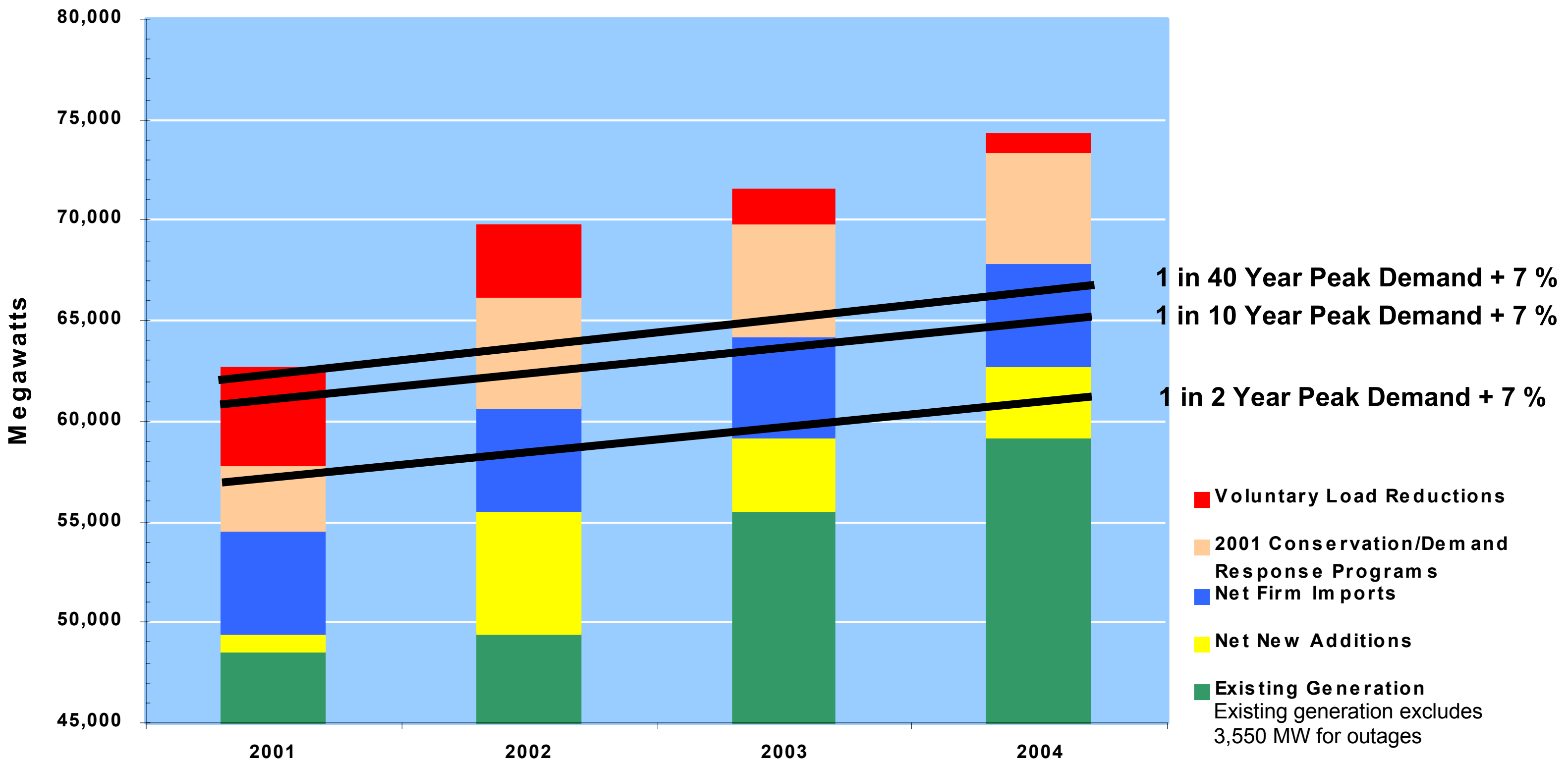
Within San Diego, significant load growth has been occurring in the hotter, inland areas contributing to increases in the area's summer peak demand because of growing air conditioning load. San Diego is highly dependent on imported power via transmission lines to meet its peak demand. If the major transmission line that connects San Diego to the southwest were to be unavailable during the summer peak demand season, all generation in the San Diego area would have to be operational to meet demand. Like the power plants in the San Francisco Bay Area, most of the large facilities in the San Diego area are more than 30 years old. A combination of additional transmission line capacity, and as new power plants in the San Diego area is needed to ensure reliable electricity service during the summer.

Summer Outlook – 2001 - 2004

The Commission's staff outlook for the summers of 2001 through 2004, shown in **Figure 4-2** reflects the impact of the Governor's initiatives to promote additional energy efficiency and new generation. As a result of these actions Statewide planning reserve margins are expected to be in the range of 15 percent to 32 percent, which should be sufficient to maintain a 7 percent operating reserve that is needed to ensure reliable service. This assessment is contingent on many factors and assumptions. Those factors that have the largest uncertainty and biggest impact on the demand/supply balance for the summer are temperature, plant outage levels, on-line dates for new generators, and implementation of demand reduction programs. The assessment also presumes that many of the market-related problems, which have exacerbated the supply situation, are successfully resolved and that surplus capacity in the LADWP control area will be made available to the ISO control area.

Figure 4-2

California Statewide Load/Resource Balance
July 2001-2004
What the Future Looks Like



August 16,

Impact of Temperature on Demand

Table 4-3 shows the impact that varying summer temperature conditions can have on electricity demand in the state. Using historical temperature data collected since 1959, the Commission staff has been able to classify temperature conditions according to their probability of occurrence. Summer temperatures for each year are averaged together and then each year is ranked from hottest to coolest. The summer with hottest average temperature equals a 1-in-40 year probability. Other years with similar, or close temperatures are averaged together to create summer temperature conditions that have a 1-in-10, 1-in-5, and 1-in-2 year probability of occurrence, or respectively a 10 percent, 20 percent, and 50 percent probability.

If temperatures during the summer of 2001 had been hotter—between the 1-in-10 and 1-in-40 year probability—and power plant outages greater than expected, combined with delays in new generation coming on-line, the reliability of the states electrical network would have been severely compromised even with all of the conservation that had occurred.

Table 4-3
Comparison of Different Temperature Conditions
On State Coincident Peak Demand
(MW)

Year	1-in-2 Temps.	1-in-5 Temps.	Difference	% Diff.
2001	54,509	56,383	1,874	3.4%
2002	55,342	57,243	1,901	3.4%
	1-in-2	**1-in-10**		
2001	54,509	57,725	3,216	5.9%
2002	55,342	58,607	3,265	5.9%
	1-in-2	**1-in-40**		
2001	54,509	58,984	4,475	8.2%
2002	55,342	59,885	4,544	8.2%

Source: CEC Staff, Draft Demand Forecast, October 2000.

Interruptible and Demand Responsive Load Programs

Interruptible and demand responsive load programs are critical to maintaining reliability as an insurance against load uncertainty due to higher than expected temperatures, and supply uncertainty due to delays in construction of new plants and abnormally high levels of plant outages.[8]

[8] Based on historical plant outage data from the California ISO from previous summers, and estimates of forced outage rates for power plants owned by LADWP, Glendale, and Burbank, the Commission staff estimated that

The total amount of capacity signed up under utility interruptible tariff programs and the ISO's demand responsive load programs for the summer of 2001 was approximately 1,795 MW. The goal at the beginning of the year was to have 2,700 MW. Participation in these programs may have been lower because of the frequency that customers under the interruptible tariffs were curtailed during the summer of 2000 and the winter and spring of 2001. However, the design of ISO's demand response programs was heavily criticized as being too complicated.

Chapter 5 provides a more detailed description of the different opportunities and programs that can reduce electricity demand.

Imports

Imports of electricity from other States have been and continue to be a key component of California's resource mix. California would be unable to meet summer peak demand for electricity without imports. The availability of imports during the summers of 2001 and 2002 will depend on the supply-demand balances in the Pacific Northwest and Desert Southwest during these periods. While a slowing of the economy could reduce the growth in electricity demand throughout the West, population growth, especially in the Southwest, is expected to continue to fuel substantial growth in electricity demand in that region. For example, the Nevada Power Company, which provides electricity to southern Nevada, forecasts a 4.2 percent annual growth in peak demand for 2000 – 2004. In contrast, the WSCC has forecast an annual growth in the neighborhood of 1.7 percent[9] for the entire Pacific Northwest.[10]

The summer of 2000 saw a decline in available imports from the Pacific Northwest and Desert Southwest. The water conditions in the Northwest were below average after several wet years, resulting in a reduction in surplus energy—electricity in excess of contracted amounts—for export. Demand growth, especially in the Southwest, combined with an absence of new generation, further contributed to a substantial decline in the amount of energy available for export to California. For the period May – August, real time net imports into California fell from an average of 6,321 MW in 1999 to 4,241 MW in 2000; the drop was sharpest in August (3,449 MW).[11] Based on firm contracts and ownership/entitlements

---

plant outages during the summer of 2001 would be in the range of between 2,100 to 3,550 MW. If plant outages during the summer of 2001 had equaled the amount of capacity that was off-line during the winter and spring of 2001—between 7,000 and 15,000 MW—then interruptible and demand responsive load would have been called on to maintain the reliability of the grid.

[9] *2000 WSCC Information Summary*, Western Systems Coordinating Council

[10] Other forecasters expect that the growth rate in the Northwest will be higher based on announced plans to locate an increasing number of data "server farms" in the region. These energy-intensive facilities are attracted to the Northwest because of a substantial amount of excess fiberoptic capacity, which is critical for E-Commerce businesses.

[11] *Analysis of Market Power in California's Wholesale Energy Markets*, Eric Hildebrand, Department of Market Analysis, California ISO, p. 5-6.

by California utilities to out-of-state plants the Commission staff had estimated net firm imports into the California ISO control area for the summer of 2001 to be 5,068 MW. For future planning purposes, the Commission staff believes that this amount of imports should be available from the Northwest and Southwest. This assumption is based the amount of new generation expected to be on-line over the next three years in these regions compared to the forecasted increases in peak demand for these same regions.

The forecasted annual incremental growth in summer peak demand over the next three years for the Southwest region is significantly less than the amount of new generation being built (see **Table 4-5**). However, Mexico could be a competitor to California for surplus power plant capacity in the Southwest, depending on the success of several proposals to build new transmission lines from Arizona into Mexico. The total amount of new power plant additions for 2001 in Table 4-5 does not include 198 MW of temporary capacity additions or 203 MW of expand existing and reactivated plants.

Table 4-5
Forecasted Growth in Southwest Summer Peak Demand
And Annual Additions of New Power Plant Capacity
(MW)

Year	2000	2001	2002	2003
Demand*	21,699	22,351	23,034	23,707
Incremental Change in Demand		652	683	673
New Power Plant Additions		1,905	1,870	3,865

* Source: *10-Year Coordinated Plan Summary 2000-2010,* Western Systems Coordinating Council, October 2000.

Table 4-6 tells a similar story for the Northwest, where expected new generation additions are significantly greater than the expected incremental increase in peak demand for the region. The total amount of new power plant additions for 2001 in **Table 4-6** does not include 480 MW of temporary capacity additions. Also, the peak demand forecast has not been adjusted to reflect the 3,300 MW of buyouts of direct service industry load, primarily aluminum smelters, and 500 MW of short-term conservation and plant closures.

Table 4-6
Forecasted Growth in Northwest Summer Peak Demand And Annual Additions of New Power Plant Capacity (MW)

Year	2000	2001	2002	2003
Demand*	49,159	49,843	50,646	51,397
Incremental Change in Demand		684	803	571
New Power Plant Additions		2,092	2,193	1,983

* Source: *10-Year Coordinated Plan Summary 2000-2010,* Western Systems Coordinating Council, October 2000.

See Appendix A for information regarding the new generation capacity that is being proposed and built throughout the WSCC region.

Both the Northwest and Southwest regions have benefited from exporting electricity to California during the summer. The Southwest utilities benefited from selling surplus generation capacity that was the result of nearly 4,000 MW of large coal-fired plants being built in the period from the late 1970s through the mid-1980s and the addition of the three Palo Verde Nuclear Plants (approximately 3,800 MW). Some of these plants are jointly owned by California utilities.

The availability of surplus power from the Northwest during the summer will depend primarily on water conditions in the Columbia and Snake River basins. Summer water flows depend in large part on the spring runoff, which in turn is dependent on precipitation and snowfall in the Northwest in the winter and early spring. While proposed changes in the operation of the Columbia River system – designed to preserve salmon habitats – will shift some generation from the spring to the summer, the variation in precipitation and snowfall can overwhelm the effects of these operating changes. Under dry hydro conditions, the maintenance of stream flows during the spring in order to preserve salmon habitats will limit the amount of water for surplus energy during the summer. Precipitation and natural stream flows in the Columbia basin during the winter and spring of 2001 were well below historical averages.

The variability of the hydropower system introduces an uncertainty for in the Northwest that does not exist in most other parts of the country. This variability can been seen in **Figures 4-3** and **4-4** which illustrate the amount of surplus capacity available from BPA for the coming summer under average hydro conditions and dry year hydro conditions.

Figure 4-3
BPA Forecast of Surplus/Deficit Capacity from Northwest
Average Versus Dry Year
August 2000 and ends July 2001
(Peak MWs 50 Hours/Week Sustained Capacity)

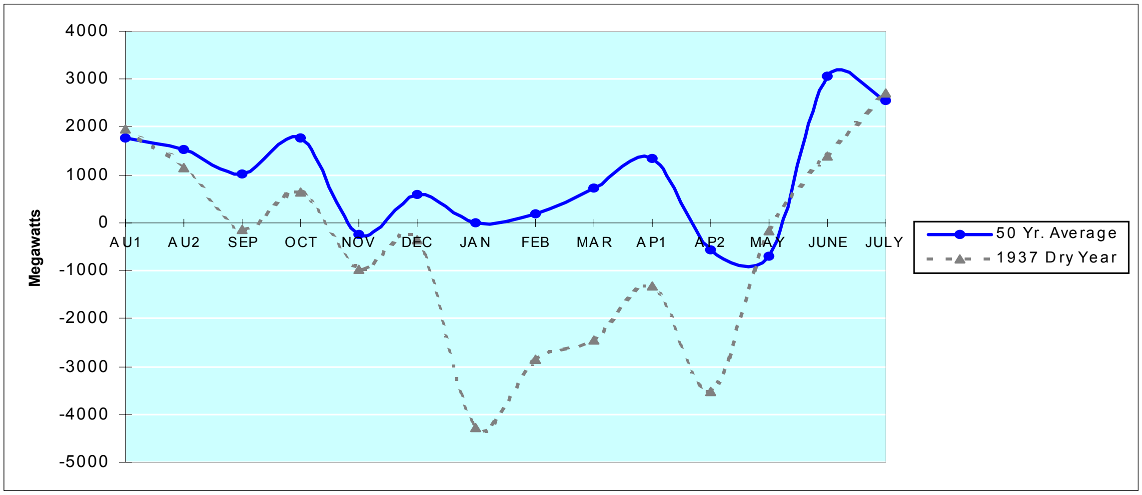
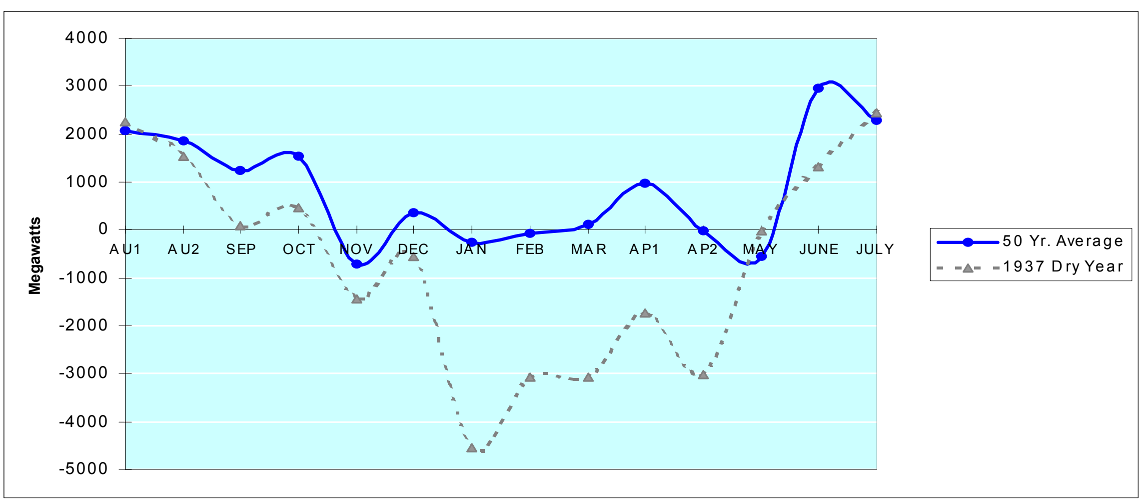


Figure 4-4
BPA Forecast of Surplus/Deficit Capacity from Northwest
Average Versus Dry Year
August 2001 and ends July 2002
(Peak MWs 50 Hours/Week Sustained Capacity)



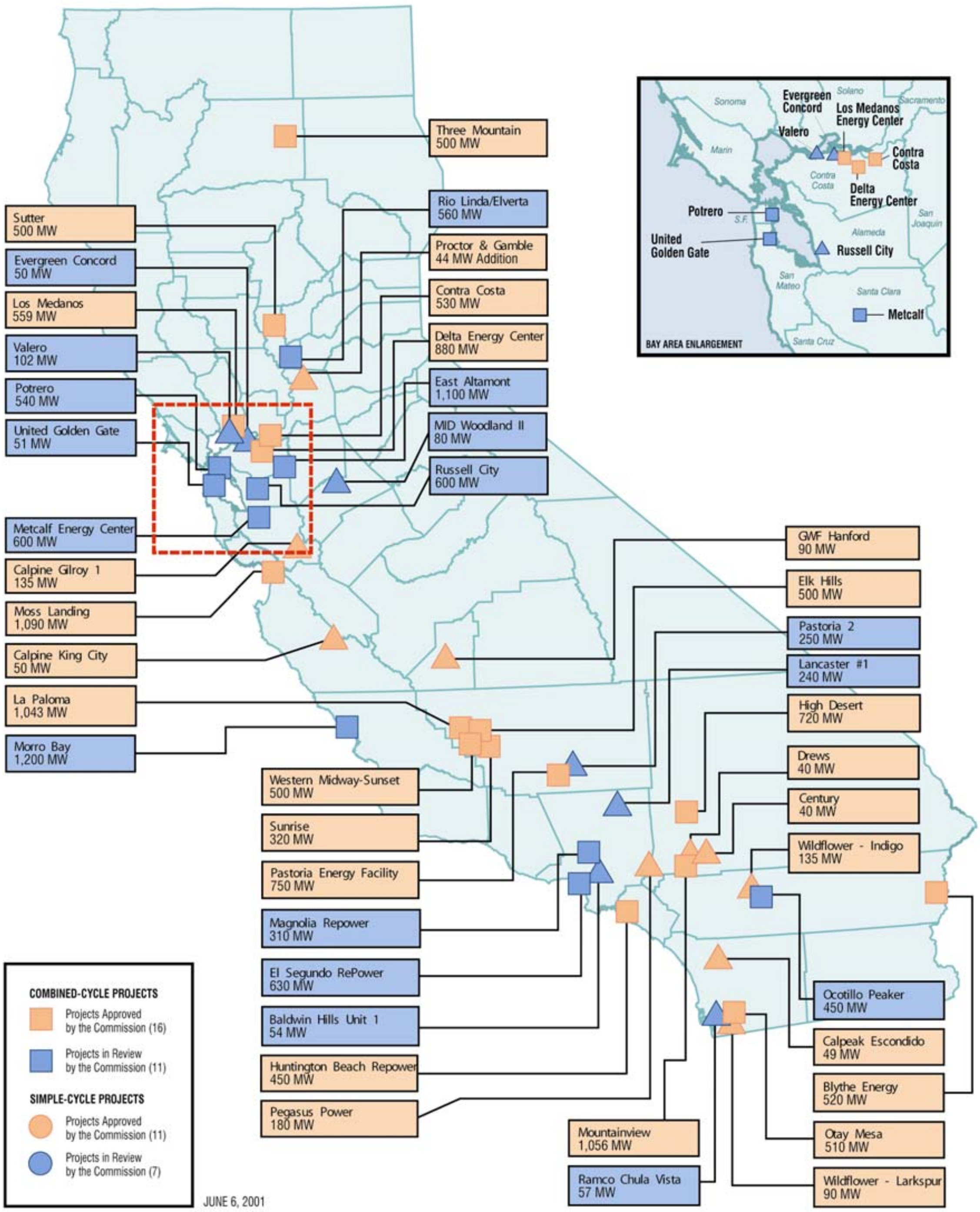
Source: BPA 1999 Pacific Northwest Loads and Resources Study, The White Book, Dec. 1999

The above graphs illustrate that surplus capacity exists from the Northwest during the summer even under dry year conditions. The impact of dry hydro conditions is seen in the fall through spring months. These graphs do not reflect the impact of the recent 2000 Biological Opinion to protect Northwest Salmon and Steelhead. The new 2000 Biological Opinion requires more water to be held back behind the dams in the winter and could potentially increase the surpluses available in the summer months.

New Generation in California

Electricity deregulation occurred in March 1998. The Energy Commission has approved 29 applications for new large and peaker power plants since deregulation. The total combined installed capacity of the approved projects—not including three projects which have withdrawn or are indefinitely delayed—is 11,303 MW. Three "major" power plants, totaling 1,415 megawatts, have come on line in 2001 and are producing electricity**.** Another 864 MW from "peaking" power plants are scheduled to come on line by the end of September. **Figure 4-5** shows the locations of each of the proposed facilities and those currently under construction. The Commission is also reviewing another 20 applications representing a combined installed capacity of 9,059 MW. Developers of an additional 28 projects totaling 10,422 MW have notified the Commission that they intend to file applications before the Commission sometime within the next 18 months. The current status of each project can be found on the Commission's website at: <HTTP://WWW.ENERGY.CA.GOV/SITINGCASES/INDEX.HTML>.

Figure 4-5



Three Mountain 500 MW
Rio Linda/Elverta 560 MW
Proctor & Gamble 44 MW Addition
Contra Costa 530 MW
Delta Energy Center 880 MW
East Altamont 1,100 MW
MID Woodland II 80 MW
Russell City 600 MW
Sutter 500 MW
Evergreen Concord 50 MW
Los Medanos 559 MW
Valero 102 MW
Potrero 540 MW
United Golden Gate 51 MW
Metcalf Energy Center 600 MW
Calpine Gilroy 1 135 MW
Moss Landing 1,090 MW
Calpine King City 50 MW
La Paloma 1,043 MW
Morro Bay 1,200 MW
GWF Hanford 90 MW
Elk Hills 500 MW
Pastoria 2 250 MW
Lancaster #1 240 MW
High Desert 720 MW
Drews 40 MW
Century 40 MW
Wildflower - Indigo 135 MW
Ocotillo Peaker 450 MW
Calpeak Escondido 49 MW
Blythe Energy 520 MW
Otay Mesa 510 MW
Wildflower - Larkspur 90 MW
Western Midway-Sunset 500 MW
Sunrise 320 MW
Pastoria Energy Facility 750 MW
Magnolia Repower 310 MW
El Segundo RePower 630 MW
Baldwin Hills Unit 1 54 MW
Huntington Beach Repower 450 MW
Pegasus Power 180 MW
Mountainview 1,056 MW
Ramco Chula Vista 57 MW
Evergreen Concord
Los Medanos Energy Center
Valero
Contra Costa
Delta Energy Center
Potrero
United Golden Gate
Russell City
Metcalf
BAY AREA ENLARGEMENT
COMBINED-CYCLE PROJECTS
Projects Approved by the Commission (16)
Projects in Review by the Commission (11)
SIMPLE-CYCLE PROJECTS
Projects Approved by the Commission (11)
Projects in Review by the Commission (7)
JUNE 6, 2001

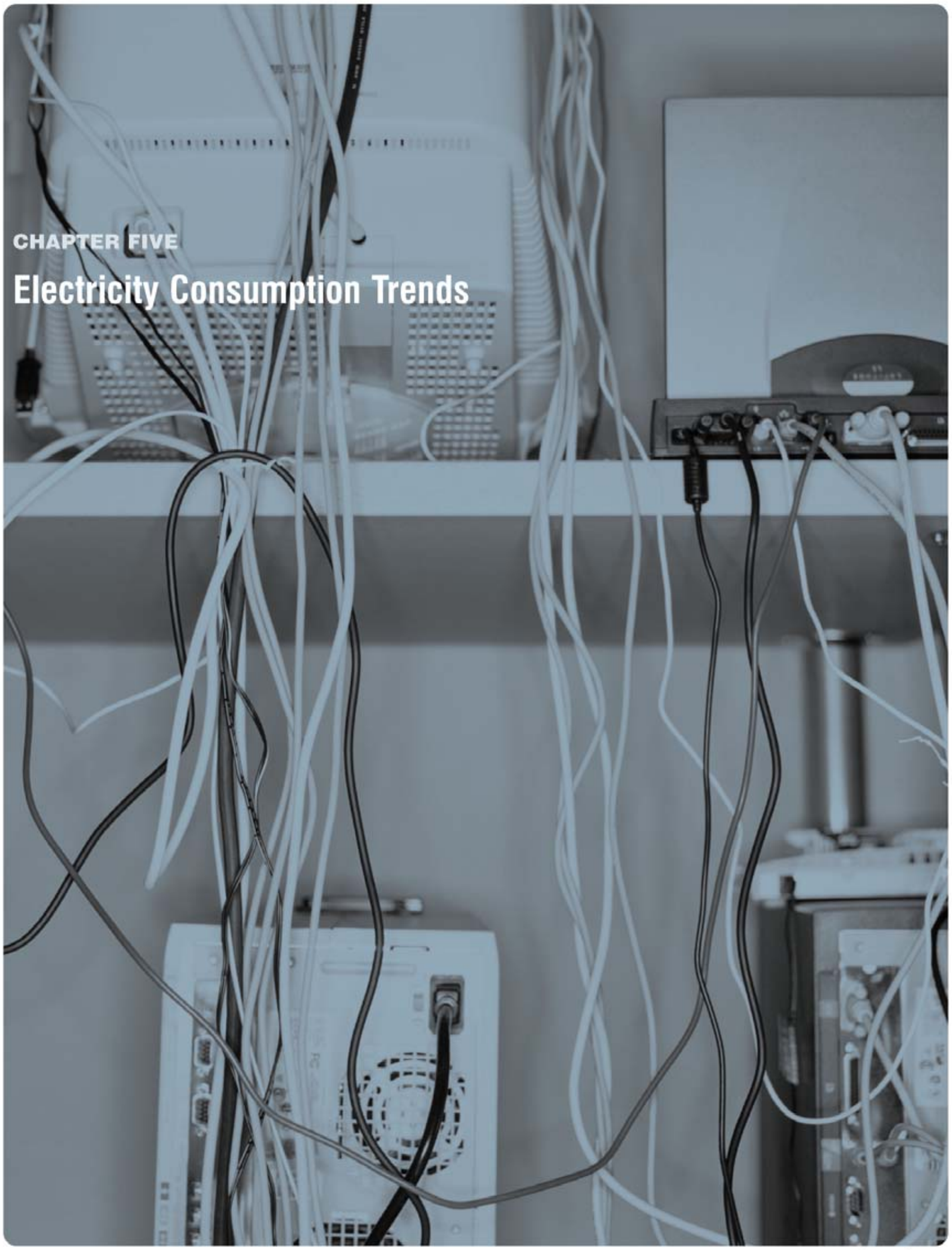


Photo credit: xxxx

Chapter 5
Electricity Consumption Trends

To determine whether there will be adequate supplies of electricity, one must have an accurate picture of the level of consumption that would be served by those supplies. As discussed in this chapter, electricity consumption can be measured in several ways and in several geographic and demographic areas.

This chapter provides an overview of:
- The purpose for electricity demand analyses
- The recorded 1998-2000 ISO peak demands
- The misconceptions of the Summer 2000 peak
- Recent trends in electricity demand growth by region and industry sectors
- The effect of temperature on energy consumption
- Other western states' energy trends
- A summary of the Commission demand outlook

The demand outlook does not include the potential impacts of recently authorized energy efficiency or load management programs. Therefore the savings from the CPUC's new summer peak programs, utility energy efficiency programs post-2002, and other programs mandated by AB 970, AB 29X and SB 5Xare not reflected in this section.

Why Analyze Electricity Demand?

Without understanding when, where, and why energy demand is changing, we lack crucial information needed to identify where additional electricity system resources may be needed, to understand the effects of prices and market structure, and to identify appropriate solutions. The goal of the Commission's energy demand analysis activities is to give the ISO, market participants, regulators, legislators, and others information about these critical trends, and thus the opportunity to take corrective action where necessary.

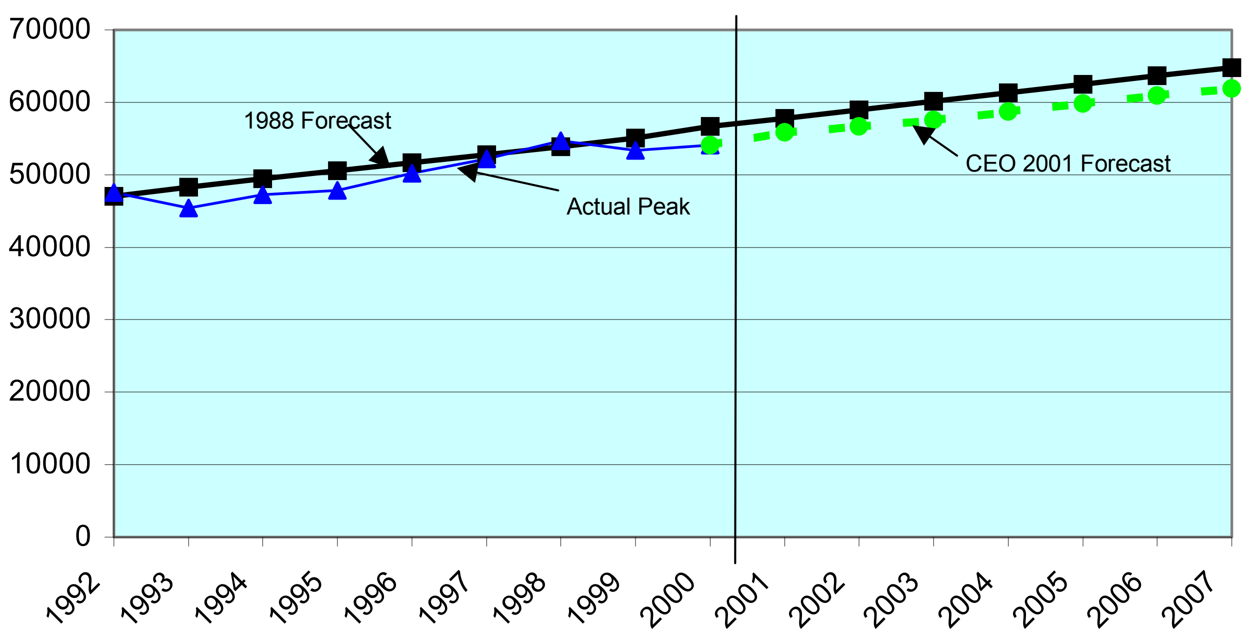
The Commission analyzes residential, commercial, industrial, and agricultural energy demand for each utility area. Forecasting models use data on economic growth, population, climates in various regions, characteristics and saturation of energy-using appliances and equipment, changes in energy utilization, and regulatory conditions. Data and models need to be continually updated to reflect market changes; this peak forecast is higher as a result of improved load shape data. The Commission also produces forecasts for the control zones used by the ISO to manage congestion. However, some possible market changes that may affect future demand are not modeled, such as changes in rate design, measures to increase demand responsiveness, or major changes in end use patterns.

How Accurate are the Commission Demand Forecasts?

The Commission's forecast models have been designed to help identify long term resource needs. Although demand projections may differ from observed consumption in any given year due to economic cycles and weather variation, they do capture the broad trends of energy demand needed to identify resource requirements and system constraints.

To illustrate, **Figure 5-1** shows the Commission's current demand forecast, compared to the forecast adopted by the Commission in 1988 as part of the 1988 Electricity Report.[1] While the 1988 forecast were off on average by about three percent, it provided a good indication of the direction of energy demand ten to fifteen years hence. The current forecast is about five percent lower than the Commission's 1998 forecast for statewide peak demand.[2]

Figure 5-1
Statewide Peak Demand (MW)



Source: California Energy Commission

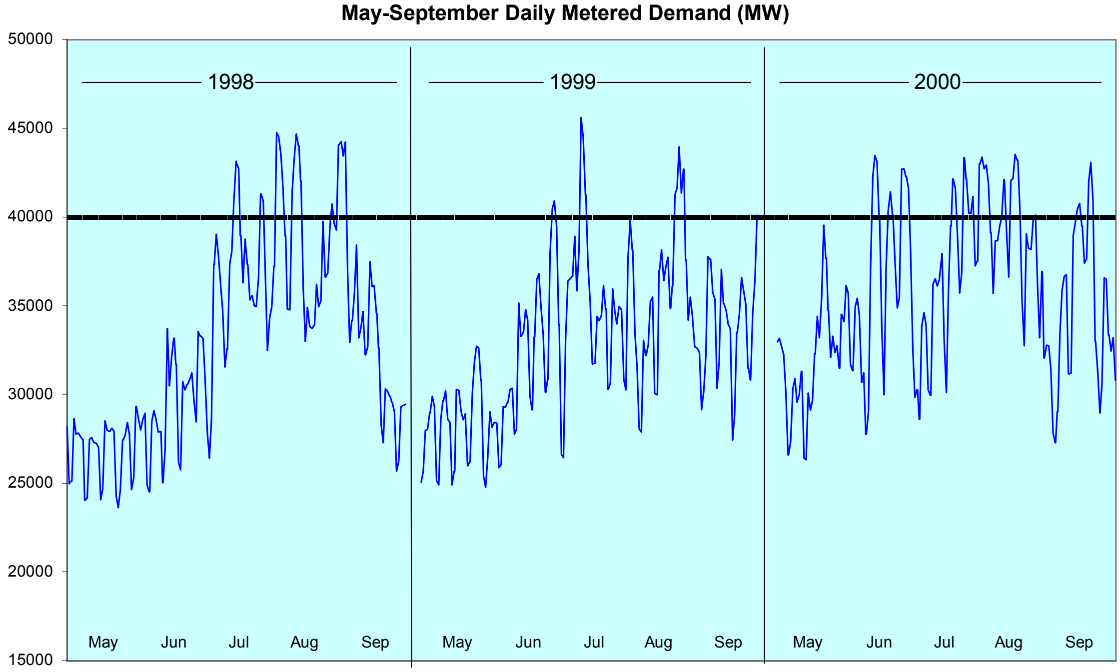
[1] "Order Adopting Electricity Demand Forecasts," May 11, 1988, Docket No. 87-ER-7, Preparation of the 1988 Electricity Report.
[2] ***California Energy Demand 2001 Forecast***.

Misconceptions of Summer 2000

During the summer of 2000, there were many opinions as to why there were so many Stage 1 and Stage 2 emergency notices declared by the Independent System Operator. Some opinions were that the industry was caught off-guard by exceptionally high load growth and therefore could not have installed sufficient generation to serve the additional load. Yet, as **Figure 5-2** shows, the actual peak for 2000 was less than the peak for 1999.

However, it is important to note that while the maximum demand was lower in 2000, there were more days of very high demand that were over 40,000 MW. It may be that frequent very high demand days may tax the electric system (especially generation) more so than just the single maximum day.

Figure 5-2
ISO Summer Demand
May-September Daily Metered Demand (MW)



Overview of California Electricity Trends

California is the tenth largest consumer of energy in the world—ranking slightly ahead of Italy and slightly behind France. However, California has one of the most energy-efficient economies of the 50 states; its per-capita total energy cost is 17 percent lower than the national average. As the population and corresponding energy use grow, we expect that technological advances, energy efficiency improvements and increased competition in energy commodities will moderate future per capita energy expenditures.

If the supply of, and infrastructure for delivering, energy were plentiful and reliable, then energy demand trends might be of limited interest to state policy makers. But as with many other elements of California's infrastructure, growth is rapidly outstripping the capabilities of our existing electricity system. California's growing population, healthy economy, and the increasing reliance of our digital economy on electricity will all continue to make monitoring and forecasting of energy demand a priority issue for the next decade.

Over the next decade, California's population will increase 15 percent to almost 40 million people – a half a million people per year. The state's economy is expected to expand more than 40 percent in the same period, faster than previous economic forecasts predicted. These robust conditions are the fundamental drivers of increasing energy use. Annual electricity consumption is expected to grow 20 percent over the next decade (**Figure 5-3**), slightly faster than the population, but only at half the rate of the economy.

How does California's use compare to the United States as a whole? The growth rate of this rising demand has been mitigated by long-standing energy efficiency policies, so that even though more electricity is used, it is used more efficiently. **Figure 5-4** shows how California has led the rest of the United States in energy efficiency. California per capita residential electricity use has not changed significantly since the early 1970s, when the Energy Commission and the Public Utilities Commission first established energy efficiency programs. **Figure 5-5** shows that the per capita electricity use trend has declined in California, compared to a continued rate of increase for the nation as a whole.

Figure 5-3
California Statewide Population and Electricity Consumption

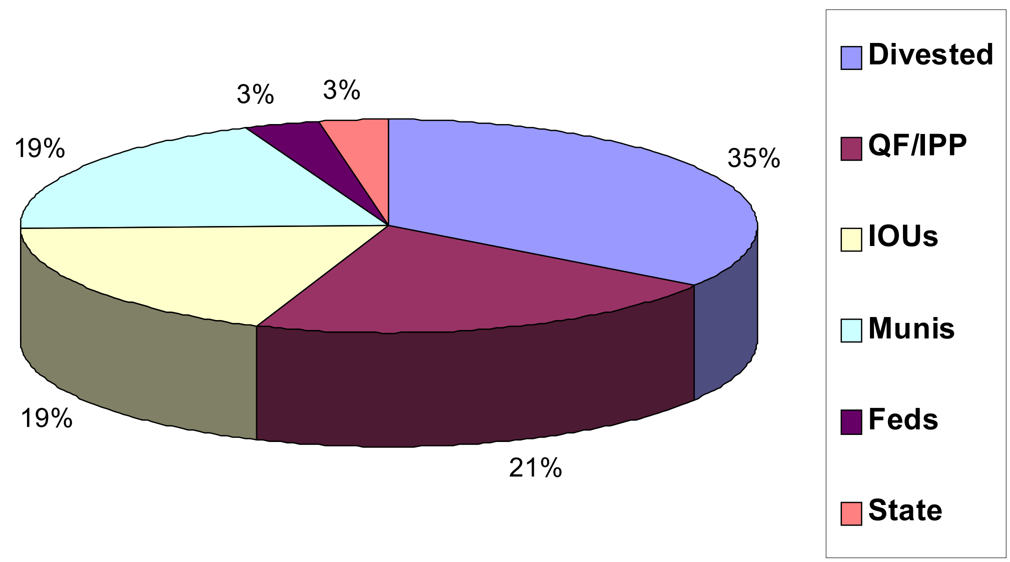


Figure 5-4

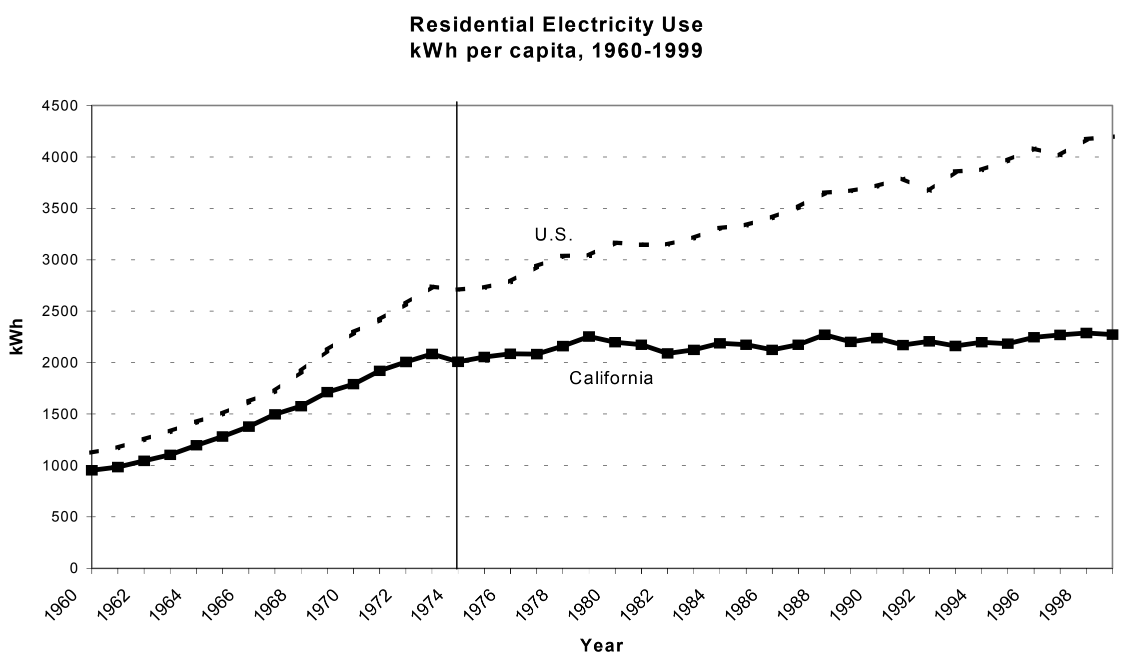
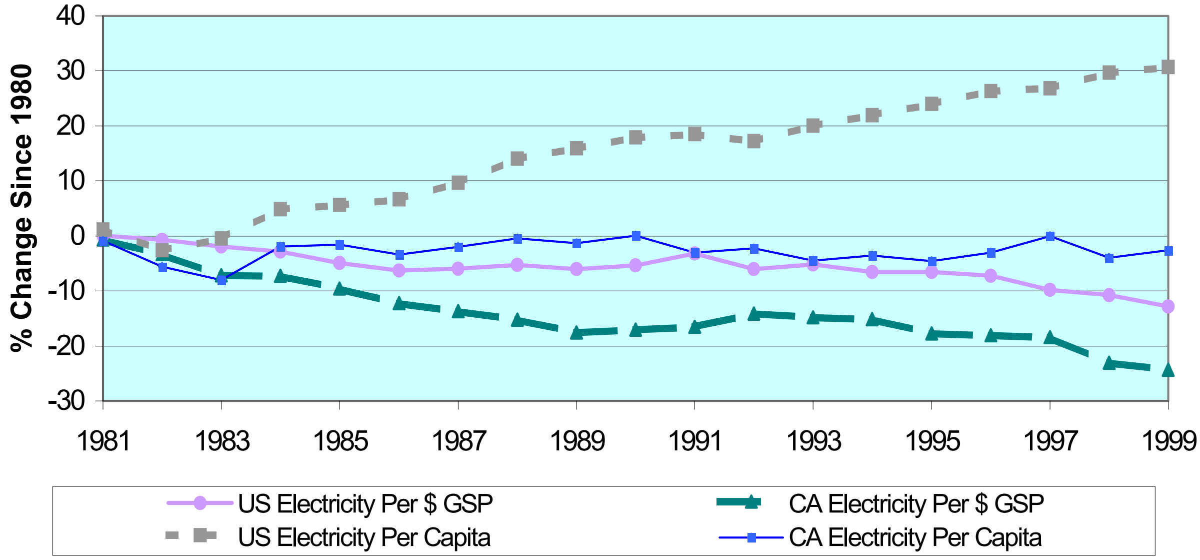


Figure 5-5
California and US Electricity Use Trends
Since 1980



Economic growth is projected to continue at a strong, steady pace, with much of the growth coming from the new information technology economy. Government standards for energy efficient appliances and buildings moderate the per capita use of electricity, but new products are increasing average use from 7,442 kWh per person in 2000 to 7,755 kWh per person in 2010.

Rapidly growing energy demand can tax the limits of available generation, transmission and distribution resources if appropriate actions are not taken. Peak demand (i.e., maximum demand) is important in evaluating system reliability, determining congestion points on the electric grid, and identifying potential areas where additional transmission, distribution, and generation facilities may be needed.

On average, peak demand grows by about 1,000 MW per year, equivalent to the output of two large, modern power plants. But even if unused power plant capacity exists, the system may not be able to deliver power where needed. Thus we need to understand peak demand needs for the overall system and to identify where demand will exceed the limits of the local delivery system. For example, over the last 10 years peak demand in San Diego and parts of northern California has grown faster than the state overall. At the same time, other parts of the western U.S. are also growing rapidly and thus competing with California for generation resources.

A Closer Look at California's Consumption

Consumption is measured in two ways – peak demand and overall energy use. These two measurements are equally important, but for different reasons. As discussed earlier, peak demand, expressed in megawatts (MW), measures the highest power requirement during a specified period of time. Generally peak demand occurs on an afternoon hour on a summer day due to increased residential and commercial air conditioning loads. This is the amount the system must be able to handle to maintain a stable electricity supply for everyone.

Table 5-1 below shows historic and forecast electric peak demand for the major utility service areas. This demand includes loads served by on-site generation and excludes losses on the transmission and distribution systems. The Energy Commission is currently updating the electricity demand forecast, which is expected to be available towards the end of the year.

Each column represents the peak for that particular utility. The last column represents the sum of the other columns. However, it is important to note that each utility may reach its peak during different hours, or even different days than others. So, when California "hits its peak" for the summer (i.e.,"coincident"), it may be different than the sum of the peaks from the utilities ("non-coincident).

Table 5-1
End-Use Peak Demand by Utility Service Area
(MW)

Year	PG&E	SMUD	SCE	LADWP	SDG&E	Other	Non-Coincident Total
1990	16,203	2,013	16,879	4,920	2,780	1,756	44,550
2000	19,377	2,465	19,315	5,031	3,252	2,048	51,488
2010	23,420	2,884	22,974	5,686	4,408	2,331	61,704
Cumulative Growth (%)							
1990-00	20%	22%	14%	2%	17%	17%	16%
2000-10	21%	17%	19%	13%	36%	14%	20%
Annual Average (%)							
1990-00	1.8%	2.0%	1.4%	0.2%	1.6%	1.6%	1.5%
2000-01	1.9%	1.6%	1.7%	1.2%	3.1%	1.3%	1.8%

Source: California Energy Commission Staff California Energy Demand 2001 forecast. "Other" includes Burbank, Glendale, Pasadena, and Imperial Irrigation District.

From 1990 to 2000, statewide non-coincident peak demand increased by 1.5 percent a year, with peak demand in northern California and San Diego growing more quickly. As a result of the recession in the early part of the decade, peak demand in southern California increased as a slower rate than the state as a whole. Over the next decade, the Commission expects statewide non-coincident peak demand to grow at an average of a 1,000 MW each year.

Another measurement is overall energy use, which is expressed in megawatt-hours (MWh). While peak demand measures a maximum consumption at a moment in time, energy use measures the total amount of electricity consumed over a specified time period (usually an hour). For example, consumption of 50 megawatts for two hours is measured as 100 megawatt-hours.

Overall energy use is as important as peak demand for several reasons. First, although a system may have sufficient resources to cover its maximum requirements (i.e. peak demand), planners must also anticipate the consumption over the course of the day or week. For example, utilities typically use hydroelectric plants and combustion turbines to help meet the peak load. However, if overall energy use during the non-peak hours is also high, utilities may need to operate such resources for more hours than planned. In the case of hydroelectric plants, this could cause the reservoirs to be depleted earlier in the season. In the case of combustion turbines, the very high cost of fuel for such plants would be incurred for a longer time and may therefore result in higher prices for power. In any event, facilities that are used at longer periods, and at maximum operating levels, can become stressed and lead to higher unexpected outages as well as higher expenses for plant maintenance.

Table 5-2 shows historical and forecast energy use for the major utility service areas.

Table 5-2
Electricity Consumption by Utility Service Area
(Thousand MWh)

Year	PG&E	SMUD	SCE	LADWP	SDG&E	Other	Total State
1980	66,197	5,352	59,624	17,669	9,730	8,406	166,979
1990	86,806	8,358	81,673	21,971	14,798	14,432	228,038
2000	102,216	9,775	93,523	24,223	18,707	13,151	261,595
2010	122,656	11,625	113,522	26,906	23,399	14,417	312,525
Cumulative Growth (%)							
1980-90	31%	56%	37%	24%	52%	72%	37%
1990-00	18%	17%	15%	10%	26%	-9%	15%
2000-10	20%	19%	21%	11%	25%	10%	19%
Annual Average (%)							
1980-90	2.7%	4.6%	3.2%	2.2%	4.3%	5.6%	3.2%
1990-00	1.6%	1.6%	1.4%	1.0%	2.4%	-0.9%	1.4%
2000-10	1.8%	1.7%	2.0%	1.1%	2.3%	0.9%	1.8%

Source: California Energy Commission Staff California Energy Demand 2001 forecast.

Highlights of Recent Trends in Electricity Demand

California has a diverse mix of geographic regions and industries. This diversity leads to differing patterns of electricity demand. For example, more growth in hotter, inland areas will increase air conditioning use and peak demand; higher growth in high-energy-using "round-the-clock" industries will lead to higher overall levels of electricity consumption. The following discussion highlights several regional and industry electricity consumption trends over the last few years (1996 – 1999).

Bay Area

From 1996 to 1999, nonresidential electricity use in the Bay Area grew by 10 percent. Growth in Bay Area electricity use was led by the high-tech sector. The high tech sector grew by 42 percent over the last 4 years. Other non-high tech industrial electricity use grew at 10 percent. Other fast growing sectors were wholesale and retail trade (15 percent growth) and financial institutions (23 percent growth). Partially offsetting the double-digit growth in these sectors was a decline of 6 percent in service industry electricity consumption and a drop of 15 percent in electricity use by government.

Sacramento Region

Nonresidential electricity use grew by 5 percent in the Sacramento Region from 1996 through 1999, or 2 percent per year. Growth in electricity use was led by high tech industries which grew at 20 percent. Other high growth sectors were services (7 percent growth), agriculture (15 percent), and other industries (10 percent). Declines in electricity use occurred in the food processing sector (8 percent drop) and in the government sector (11 percent decline).

Southern California

Compared to the high growth in the two northern California regions, electricity use in southern California grew a slow rate. Southern California electricity use increase by 2 percent from 1996 – 1999, an equivalent of ½ percent per year. As in other regions, electricity use increased in high tech industries, as well as in trade, financial institutions, and services. However, growth in southern California in these sectors did not match the double-digit growth seen in northern California. High-tech industry electricity use in southern California grew by 2 percent; use by wholesale and retail trade increased by 4 percent; and use by service industries rose by only 1 percent.

California Energy Outlook by Sector

Residential electricity use is expected to increase by 1.7 percent each year. Commercial and industrial electricity use is forecast to grow faster, with commercial use projected to grow at 2 percent per year and growth in industrial use expected to be 2.2 percent annually.

Residential Sector

Three-quarters of the increase in residential electricity use comes from population growth. The remaining one-fourth is due to growth in use per person as a result of strong growth in personal income and more housing being built in hotter regions of the State. Increasing personal income allows customers to buy new electrical appliances such as computers, printers, additional televisions, or refrigerators.

Commercial Sector

Over the forecast period, commercial electricity use is expected to increase 2.1 percent per year. Commercial use has been driven both by an increase in the number of businesses, measured in square footage, and the use per firm. Commercial floor space increased 2.4 percent per year between 1980 and 1998. Over the forecast period, the growth of commercial floor space is expected to slow to a more moderate rate of 1.5 percent annually. From 1980 to 1998, electricity use per square foot of floor space grew at an annual rate of 0.7 percent, and it is projected to increase by 0.5 percent annually over the forecast period.

Other factors influencing commercial energy use are vacancy rates, taxable sales, and population. For example, growth in school age population will lead to increases in energy consumption by schools.

Industrial Energy Sector

Industrial energy use is driven primarily by industrial employment and the output of manufacturing plants, measured by value of shipments. Shipments are expected to grow by 4.5 percent per year over the forecast period. Decreasing use per shipment partially offsets the growth over the forecast period. Use per shipment declines by an annual rate of 2.3 percent. The declining use per dollar of shipments represents a decrease in energy intensity of production that can be explained by both increased energy-efficiency and a shift to a mix of industries that produce less energy intensive products. Combining the 4.5 percent growth in shipment and the 2.4 percent decrease in use per shipment results in the 2.1 growth in industrial electricity use.

Effect of Temperature on Energy Consumption

Summer temperatures are the single biggest variable in determining whether actual peak demand will be higher or lower than the long-term trend. The peak demand forecast is based on 'typical' temperatures—temperatures that are expected to occur one out of every two years (1 in 2). A Commission staff report, *High Temperatures & Electricity Demand*[3], examined the effects of high temperatures on peak demand and found that a hot year (1 in 5) would increase demand 3.5 percent and that in a very hot year (1 in 40) peak will be 8.0 percent higher than normal. A one degree increase in temperature leads to a 900 MW increase in statewide demand. (900 MW is the equivalent of the combined peak use of Burbank, Glendale and Pasadena.)

In addition, "heat storms" (3 consecutive very hot summer days) not only impact the peak demand each day, but also significantly impact overall energy consumption. Heat gain in commercial and residential buildings will require increasingly intensive use of air

[3] The staff report can be found at <HTTP://energy.ca.gov/1999-07-23_HEAT_RPT.PDF>

conditioning during late night hours to maintain temperature or, in the case of commercial buildings, to "pre-cool" for the upcoming day. Such additional loads also impact power plants, as we discussed above, by requiring longer operations that may lead to a higher potential for unexpected outages and higher maintenance expenses.

Overview of Other Western States Energy Trends

California is not the fastest growing western state. Simultaneously, population and energy intensive development have been booming in neighboring states – states that traditionally exported surplus electricity to California. Demand in most of the western region grew much faster than forecasted. Load growth in the Southwest, especially in Southern Nevada and Mexico, is expected to be significantly greater than load growth in California. Demand growth is largely a result of increasing population, with the metropolitan areas in the Southwest having the fastest growth rates in the nation. population increases in the West outpaced the growth rate throughout the rest of the United States in the last decade.

Summary of California's Electricity Demand

California's peak demand has been growing at an average of 2 percent per year. This growth has been fairly consistent over the last decade. However, overall electricity use is expected to grow 19 percent in the upcoming decade. Thus, while meeting peak demand continues to be the critical task for California's operators, growth during non-peak hours is increasingly important and must be addressed.

Yet, the growth of electricity use in California is not the only focus for planners. Extraordinary growth in the Pacific Northwest and the Desert Southwest has caused power supplies to be shifted away from previous use as imports to California. These supplies are now being reserved for native load requirements in those Regions. In addition, California's in-area generation is increasingly being used to supply the Pacific Northwest (not just during winter, but also during summer evenings).

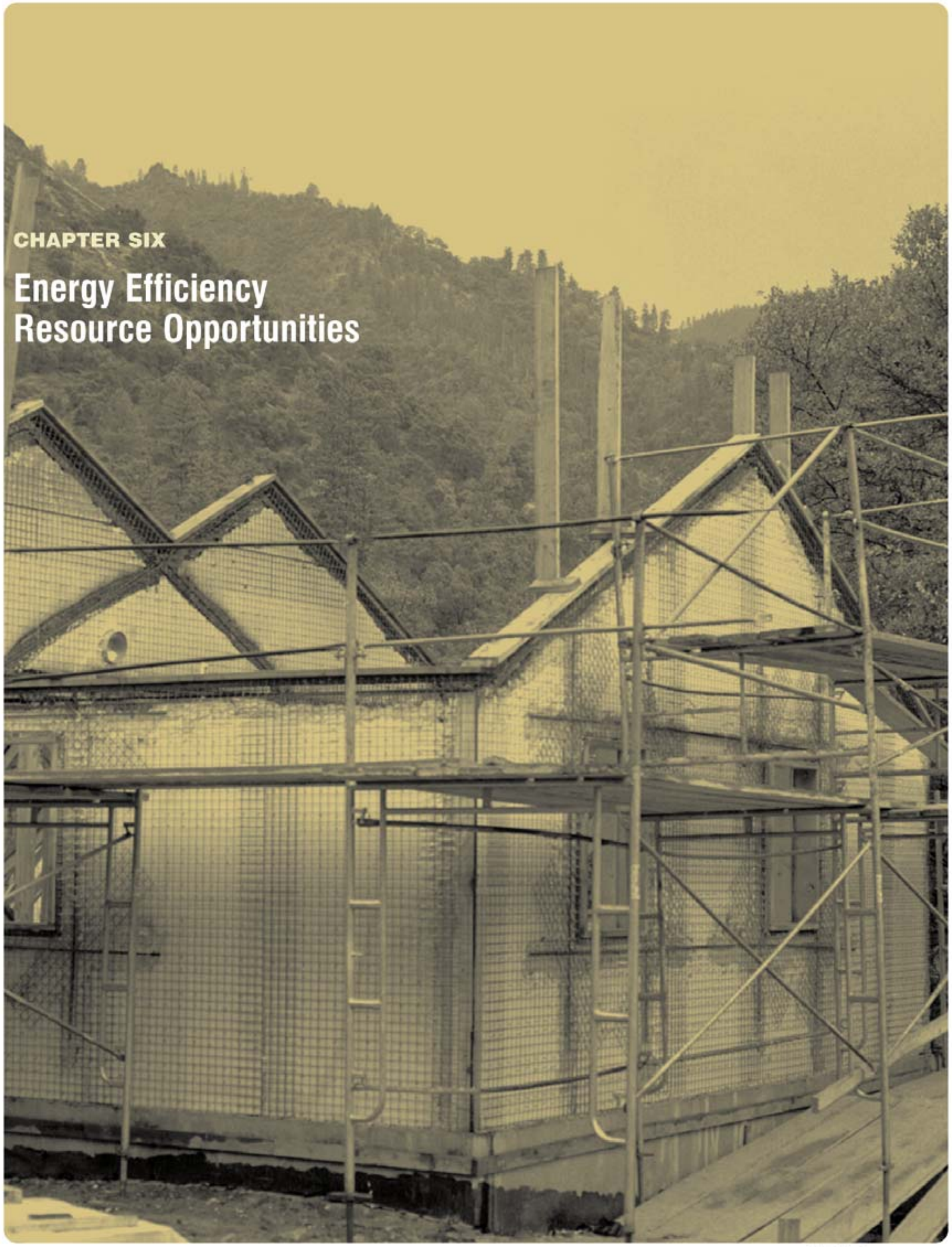


Photo: Dave Parsons

Chapter 6
Energy Efficiency Resource Opportunities

Energy efficiency programs reduce the energy dependence of California's economy, make businesses more competitive, and allow consumers to save money and live more comfortably. In addition, energy efficiency programs defer the need for new generation or transmission capacity, prevent environmental degradation, and help consumers control their utility bills.

While the fundamental goal of California's efficiency programs and standards continues to be to promote cost-effective energy efficiency and conservation, the strategies emphasized to meet this goal have varied with the regulatory and market environment. Before the restructuring of electricity markets, utilities and state agencies invested in energy efficiency as a cost-effective alternative to generation. With the passage of AB 1890, the focus shifted to achieving longer-term energy savings that would be sustainable after public subsidies ended. The first section of this chapter looks at past savings from energy efficiency programs.

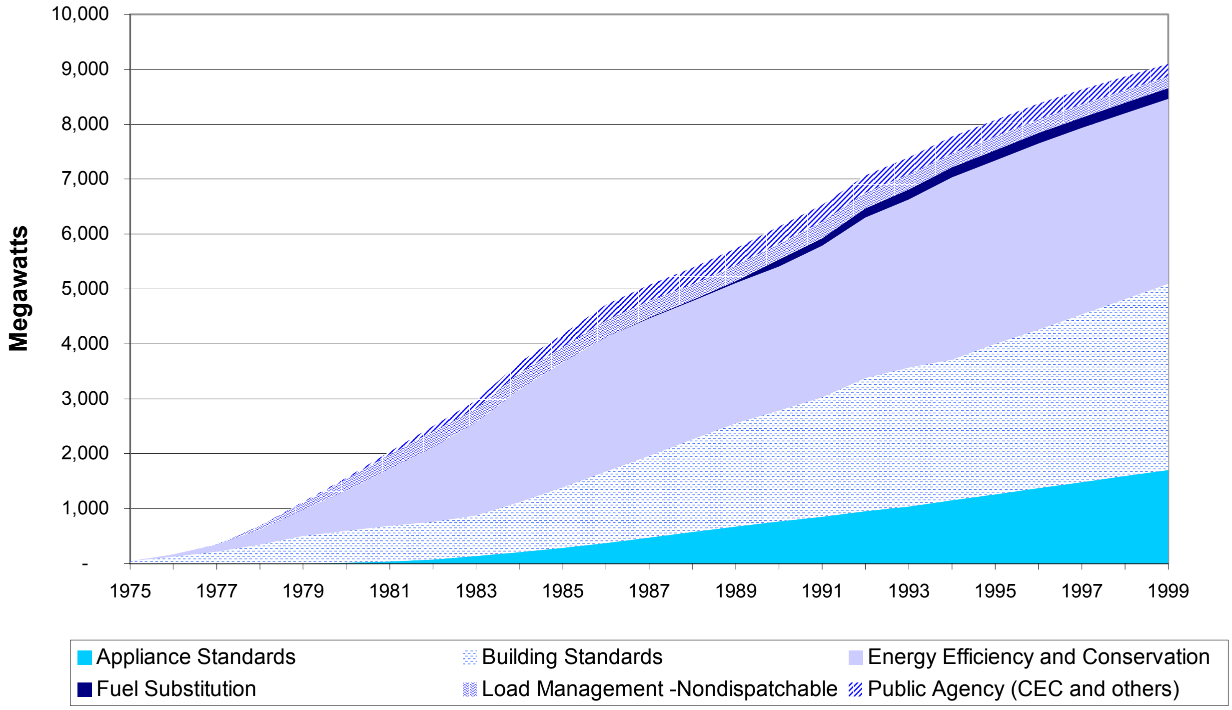
However, with recent electricity market strains, state and utility energy efficiency programs are refocusing on end uses with the largest peak impacts to help prevent shortages and price spikes. In addition, legislation has been recently enacted to provide immediate relief in the summers of 2001 and 2002. This new legislation is AB 970, SB 5x, and AB 29x. Although these programs target demand reductions during the summer peak demand period, many programs will also produce year-round savings through improvements to lighting, water pumping, and heating and cooling system efficiency. The second section of this chapter presents the new programs that have been put in place to reduce peak demand.

A newly emerging role of energy efficiency is also to improve future reliability by helping correct fundamental weaknesses of the market. The Governor, Legislature, Commission, and others have identified lack of price responsiveness in the current market as a serious problem, but implementation of metering and interval pricing could have short-term adverse impacts if energy consumers are unprepared. Energy efficiency programs can help mitigate these concerns by providing the information and tools to help consumers make effective choices about energy consumption and energy efficiency investments. The third section of this chapter discusses real time pricing and demand responsiveness.

Past Energy Savings from Energy Efficiency

Demand-side management (DSM) has included a variety of approaches, including energy efficiency and conservation, building and appliance standards, load management, and fuel substitution. Since 1975, the displaced peak demand from all of these efforts, shown in **Figure 6-1**, has been roughly the equivalent of eighteen 500-megawatt power plants. The annual impact of building and appliance standards has increased steadily, from 600 MW in 1980 to 5,400 MW in 2000, as more new buildings and homes are built under increasingly efficient standards.[1] Savings from energy efficiency programs implemented by utilities and state agencies have also increased (from 750 to 3,300 MW).

Figure 6-1
Statewide Peak Impacts of Selected DSM Programs and Standards Implemented Prior to 2000

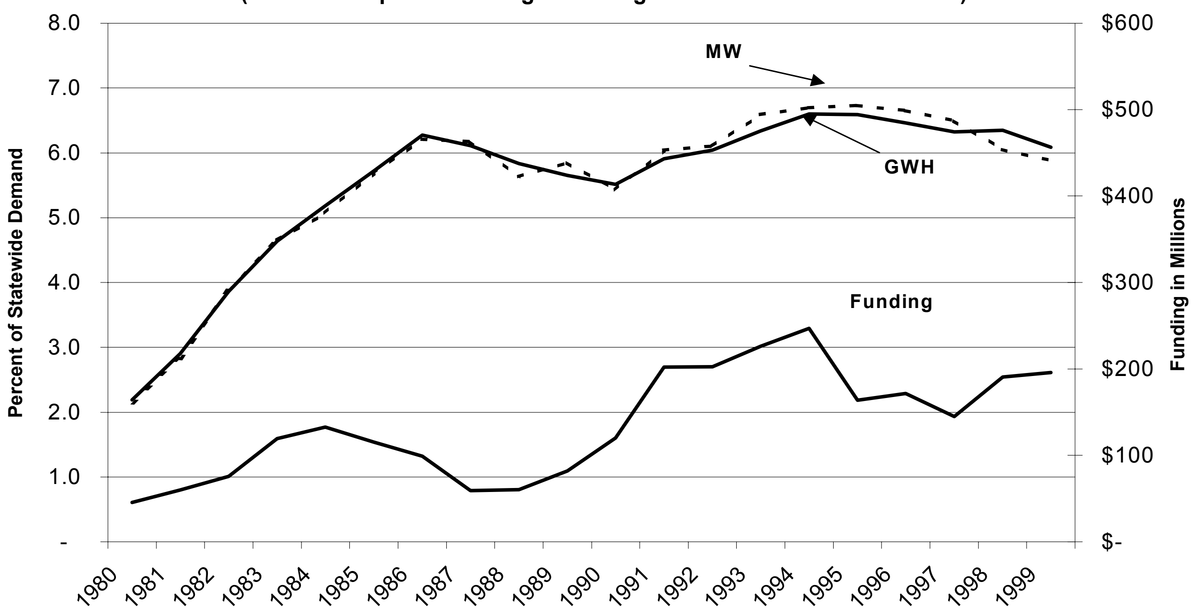


Source: California Energy Commission

[1] The methodologies used to estimate the effects of prices and standards are described in CEC Commission Report, *California Energy Demand: 1995-2015: Volume II: Electricity Demand Forecasting Methods* (July 1995) California Energy Commission, publication number P300-95-005.

In addition to the standards, programs managed by the three investor-owned utilities (IOUs)[2] provide the second largest contribution to displacing demand. **Figure 6-2** shows annual utility funding levels and energy savings as a percent of total demand.[3] After a decade of rapid increases, the growth in electricity savings declined in the late 1980s as a result of IOU spending cuts driven by falling energy prices and surplus generation capacity. IOU spending and the amount of demand displaced increased in the early 1990s when the CPUC instituted shareholder incentives for cost-effective energy efficiency programs with measurable results. In the mid- to late-1990s, reduced funding has resulted in a leveling off of the benefits from IOU energy efficiency programs. After the CPUC announcements in 1994 of the transition to restructuring, the uncertainty about the future of DSM incentives lead the utilities to dramatically cut DSM budgets. In 1996, AB 1890 set annual funding at this relatively lower level. As a result, the contribution of energy efficiency programs to reduce demand continues to decline.

Figure 6-2
Total Impact of Energy Efficiency Programs Managed by IOU's as a Percentage of Actual 2000 Statewide Demand (Reflects Impacts of Programs Begun Between 1975 and 2000)



Source: California Energy Commission

---

[2] Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric.

[3] Savings are derived from estimates of "first year" energy savings achieved by programs as reported by the IOUs to the CPUC annually. The Office of Ratepayer Advocates of the CPUC publishes summaries of these reports, most recently in "The Public Purpose Energy Efficiency Surcharge: Trends and Patterns in the Costs and Benefits of Utility Administered Energy Efficiency Programs," March 8, 2000. Where utilities did not report impacts, staff estimates based on funding level and program design are used. The methodologies used to project annual savings for each year of each program's implementation are described in "Uncommitted Energy Efficiency Scenarios," April 3, 1996, prepared for the Staff Workshop on ***ER 96*** Uncommitted Energy Efficiency Scenarios, April 17, 1996.

Summer Peak Load Reduction Programs

New programs have recently been initiated to quickly implement energy conservation and peak load reductions to mitigate possible supply-demand imbalances this summer. These initiatives include AB 970, SB 5x, and AB 29x.

In July 2000, the CPUC directed utilities to implement new peak load programs in the summer of 2001. In August 2000, the California Legislature and Governor approved AB 970, which directed both the Energy Commission and the CPUC to implement cost-effective energy conservation and demand-side management programs. In April 2001, the California Legislature and the Governor approved SB 5x and AB 29x, which direct the Commission, CPUC, and other state agencies to implement, as quickly as possible, peak load reduction programs. These two bills create a landmark energy efficiency and demand reduction program that represent the largest conservation effort ever launched by a single state.

CPUC/Utility Summer 2000 Energy Efficiency Initiative

Citing the Energy Commission's analysis of the summer heat storms of 1998[4] and the need for the ISO to call for curtailments of customers on interruptible tariffs, the CPUC recognized the potential for a chronic supply and demand imbalance over the next few years. In response, the CPUC initiated a program focused on immediate delivery of measurable demand and energy usage reductions beginning in the summer of 2000.

This program, known as the Summer 2000 Energy Efficiency Initiative, will continue through 2001 and is in addition to the existing utility-administered energy efficiency programs discussed in the previous section. The CPUC awarded a total of $72 million dollars in unspent energy efficiency funding from prior years (1998 and 1999) to private parties to achieve an estimated 68 MW of peak demand reductions during each of the next two summers. Some of the programs selected by the CPUC to reduce peak load include:

- The Oil Producers Fluid Pumping Efficiency Program to improve the efficiency of motors, cooling, disposal, and oil well pumping systems;
- Residential refrigerator recycling; and
- The Hard-to Reach residential program to promote water heating, lighting, and insulation measures in the residential multi-family and other hard-to-reach sectors.

[4] California Energy Commission Staff Report, High Temperatures and Electricity Demand, An Assessment of Supply Adequacy in California, July 1999. (htp://www.energy.ca.gov/Electrcity/1999-07-23_HEAT_RPT.pdf)

CPUC AB 970 Activities

AB 970 directs the CPUC to expand and accelerate programs with significant peak impacts including residential and commercial weatherization, programs to improve the operating efficiency of heating, ventilation and air-conditioning (HVAC) equipment in new and existing buildings, and new construction programs. Other areas the CPUC is to target include:

- Incentives to equip commercial buildings with the capacity to automatically shut down or dim nonessential lighting and incrementally raise thermostats during peak electricity demand period;
- Incentives payments to customers for load control and distributed generation;
- Incentives for renewable or super clean distributed generation resources; and
- Peak reduction programs that encourage electric customers to reduce electricity consumption during peak power periods.

To implement AB 970, the CPUC is pursuing two strategies. First, it has directed the utilities to modify existing programs as part of the 2001 energy efficiency program planning process. The CPUC added the objective of achieving peak demand savings to the program goals of the existing utility energy efficiency programs.

Second, the CPUC is developing a separate plan for programs that promote self generation and demand responsiveness. The demand responsiveness programs will test the viability of measures such as programmable, internet-connected thermostats that allow customers to easily adjust energy-using equipment in response to current information about electricity costs. The self generation program will provide financial incentives for installation of both renewable and non-renewable generation, and will require utilities to waive interconnect and standby fees.

Energy Commission AB 970 Programs

AB 970 allocates $50 million to the Energy Commission for a program to reduce peak electricity demand in the summer of 2001. The program goal is to reduce electric load on the California system grid by at least 192 MW during the peak summer period. The Commission has selected an independent contractor to measure and verify the peak impacts achieved.

The program will seek to achieve measurable peak demand reduction quickly and cost-effectively by providing incentives for the following measures:

- *Demand Responsive HVAC and Lighting* promotes systems that will adjust how much electricity cooling systems, lighting, or other equipment uses in response to either the price of electricity or an "emergency" signal from an electric distribution company.

- *Cool Roof Retrofits* reduce the electrical demand associated with solar energy absorbed on roof surfaces and rooftop ducts of public and commercial buildings.
- *State Buildings and Public University* strategies will include the development of customized peak electricity demand reduction plans, training of building managers/operators, and load verification software and hardware to enable participation in price responsive or emergency load reduction programs.
- *Light Emitting Diode Traffic Lights* can reduce energy use per signal by 80 to 90 percent.
- *Water and Wastewater Treatment Pump and Related Equipment Retrofits* encourage more efficient pumps, control systems and related equipment in public water systems, and software and hardware to enable participation in load reduction programs;
- *Innovative Efficiency and Renewable Projects* may either reduce load on the electricity supply system or provide new supply.

The Energy Commission's AB 970 program has been very successful. By January 2001, all of the allocated money had been spent. Many proposals were received that were not able to be implemented because funds had run out.

California Energy Commission Revised Building Standards

In response to AB 970, the Commission accelerated its schedule for revising appliance and building efficiency standards. The revised standards for residential and commercial buildings take effect June 1, 2001. Initial changes to the appliance standards were approved on February 7, 2001. The new standards focus on measures whose benefits and costs are well documented, thus enabling a speedy adoption and implementation process for changes that are expected to produce immediate cost-effective peak savings.

Key changes to the residential standards include requirements for duct sealing, low solar gain glass, and attic radiant barriers. The new residential standards alone are expected to reduce demand by more than 150 MW each year. The commercial standards affect windows, cool roofs, heating and cooling systems, and lighting, with an estimated impact of 47 MW in 2001. Changes to appliance standards being considered include new standards for air conditioners, small water heaters, illuminated exit signs, commercial clothes washers, commercial refrigeration, and torchiere fixtures.

Recent Peak Demand Reduction Programs

In response to continued disarray in the electricity market and prospects for many days of rotating outages in the summer, the Governor and Legislature proposed several demand reduction proposals. In April 2001, Governor Gray Davis signed SB 5x and AB 29x, which was been passed by the Legislature in an extraordinary session.

Some of the SB 5x and AB 29x programs provide new funding for programs that have already depleted AB 970 funding. SB 5x and AB 29x also provide additional funding to the existing Demand Responsive Building Program, Innovative Program, and Cool Building Programs. SB 5x and AB 29x also funds new demand reduction programs. These included the Mobile Efficiency Brigade where California Conservation Corp members go door-to-door in low-income neighborhoods giving away energy saving compact fluorescent light bulbs.

SB 5x and AB 29x allocated $859 million to the Energy Commission, CPUC, and other state agencies for peak load reduction programs. The programs are expected to have an impact of over 2,000 MW during the summer of 2001 and an impact of over 3,400 MW when they are fully implemented. **Table 6-1** summarizes the programs.

The program with the most significant impact is the Real Time Meter program with an expected peak reduction of 1,500 MW. This program will spend $35 million to install real time meters on all customers above 200 kW in size. This widespread installation of real time meters will make increased demand responsiveness possible in the state.

Demand Responsiveness

A key element missing from California's electricity market design is demand responsiveness – consumption that varies according to hourly prices. Legislators, policy markers and market participants agree that greater demand responsiveness is essential for four principal reasons:

- To allow consumers to pay for the electricity they want and not for electricity which is too expensive
- To lower costs for everyone by reducing peak demand and hence the very high wholesale prices resulting from market power of generators.
- To allow the market to reach an equilibrium between demand and supply

To allow both consumers and energy service providers to select the manner of managing price risk which meets individual needs.

The ability to respond varies among end-use consumers, and several different types of programs are necessary for price responsiveness to be effective and fair. A modern electricity market needs some consumers to change their uses quickly. The market also needs all consumers to invest in the equipment and behaviors that will manage their electricity use and their exposure to the risks of price volatility. Demand responsiveness does not mean consumers should swelter in the summer because air conditioning costs too much, or that businesses should send employees home because a production run must be terminated. California must develop demand responsive programs that meet the different needs of consumers and introduce discipline into the market without inflicting hardship.

Table 6-1

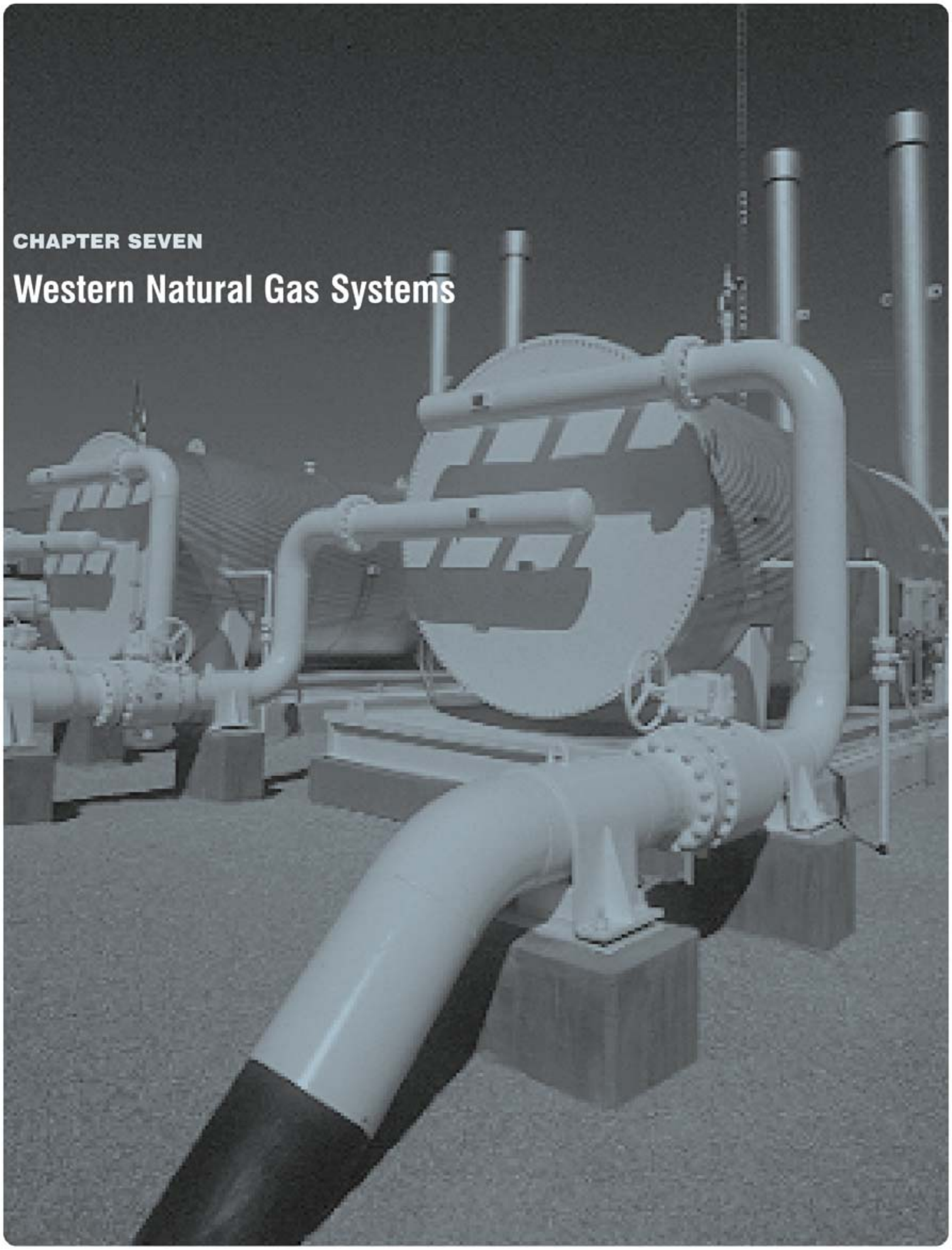
Agency	Measure	Total Appropriated ($ million)	Total Peak Reduction (MW)
CPUC	Residential Air Conditioning and Appliances	$50	123.3
	Increase CARE program	$100	
	Low-income Weatherization	$20	8.0
	Oil and Gas Pumping Efficiency	$12	16.0
	Commercial Lighting Incentives	$60	60.0
Energy Commission	Municipal Utility Programs	$40	50.0
	Demand Responsive Buildings	$35	164.0
	Low-energy Use Building Materials	$30	90.0
	Innovative Peak Programs	$50	120.0
	Agricultural Programs	$70	105.0
	Classroom Outreach	$7	
	Municipal Water District generation retrofit	$10	30.0
	Real Time Meters	$35	1,500.0
	Local government loans and grants	$50	50.0
	Geysers Injection System	$4.5	10.0
Energy Commission	Renewable Resources	$30	10.0
Dept. of Consumer Affairs	Public Awareness Initiatives	$10	1,000
Dept. of General Services	State Energy Projects	$40	40.0
Dept. of Community Services and Development	Low-income Assistance	$120	
Trade and Commerce Agency	Renewable Energy System Loans	$40	21.0
California Conservation Corps	Mobile Efficiency Brigade	$20	10.0
California Alternative Energy and Advanced Transportation Financing Authority	Renewable Energy Financial Assistance	$25	

The Commission's demand responsiveness goal is for every consumer to make an informed choice about the use of power. When these choices are aggregated, they will help the market finds its natural balance between supply and demand. Such responses will be feasible due to new communication equipment, controls and software that allows for rapid assessment and response. A mix of programs is necessary to meet different consumer information and value profiles. **Appendix A – Increasing Demand Responsiveness in Electricity Markets** provides an overview of efforts to increase demand responsiveness. The appendix also provides recommendations for action by the Energy Commission and other agencies.

Summary

Energy efficiency programs and standards have long contributed to a reliable electricity system by slowing demand growth and speeding replacement of inefficient equipment. Over the next two summers, they will also contribute immediate reductions in peak demand. However, policy makers now must move beyond short-term solutions and begin to improve market signals so that emergency measures are no longer needed. Energy efficiency programs can help protect against economic shocks and inequities to consumers as we transition to a better functioning, more competitive market by:

- Helping consumers protect themselves from surprise bill increases,
- Helping consumers understand new rate structures and how energy efficiency measures and price-responsiveness strategies can benefit them,
- Identifying the most viable demand responsiveness strategies for different market segments, and
- Supporting testing and promotion of technologies to allow end users to easily respond to high energy prices.


CHAPTER SEVEN
Western Natural Gas Systems

Chapter 7
Western Natural Gas Systems

This chapter briefly describes the natural gas resource base, including in-state supplies, the share of natural gas resources available to California, and the pipeline system that transports natural gas to California and its natural gas consumers.

Overview

The clean-burning characteristics of natural gas make it the primary fuel of choice for non-transportation uses, not only in California, but throughout the United States. Moreover, as competition in the power-generation sector expands, natural gas will become even more important as it dominates generation fuels.

There are two basic forms of natural gas production: associated gas and nonassociated gas. Crude oil development may produce associated gas along with crude oil. Gas producers extract nonassociated, or dry, gas from gas fields. Gas fields yield little or no crude oil. Nearly three-quarters of California gas production is associated gas and the rest is nonassociated. Environmental restrictions and investment incentives have recently limited offshore production in state waters. This illustrates how the resource base can be constrained for additional California production.

Natural gas goes through several processes before it reaches final consumers. First, drilling rigs extract natural gas from underground reservoirs. Small pipelines then gather the extracted gas and transport it to processing plants that improve the quality of the raw gas by extracting water, heavier natural gas liquids, and inert gases.1 Finally, interstate pipelines transport the gas over long distances either directly to large-volume customers or to local utility distribution companies who supply gas to their retail customers.

[1] Before putting the gas into interstate pipelines, gas producers must verify that the heat content of the refined gas has reached pipeline quality, usually ranging from over 900 to 1,030 British thermal units (Btu) per cubic foot, and add sulfur compounds to give the gas its distinctive odor.

Natural Gas Resource Base
Assessment of Resources in the Lower 48 States

For purposes of supply assessment, there are three major categories of natural gas resources: proven reserves, reserve appreciation, and potential resources. Proven reserves are those located in basins where wells are currently in production. Reserve appreciation accounts for changes in the economic recoverability of proven reserves. Potential resources are those located in regions where analysis and testing indicate natural gas can be economically produced, but where no production is underway.

As **Table 7-1** shows, EIA estimates2 that there are approximately 152 trillion cubic feet (Tcf) of proven reserves in the lower 48 states. Approximately 40 percent of this total is located on the Gulf Coast, with another 19 percent in the Anadarko region. Potential resources in the lower 48 states are found principally in the Gulf Coast and Rocky Mountain basins.

Table 7-1
Lower 48 Natural Gas Resources [2]

Supply Region	Proven	Potential	Reserve Growth	Region Subtotal	Percent of Total
Gulf Coast	59.563	194.130	76.984	330.677	33.9
Rocky Mountain	15.028	168.854	7.436	191.318	19.6
Anadarko	28.087	23.135	52.745	103.967	10.7
Appalachia	7.006	69.719	3.794	80.519	8.3
San Juan	18.630	52.480	8.456	79.566	8.2
Permian	14.463	20.418	27.073	61.954	6.4
Northern Great Plains	2.149	53.624	3.946	59.719	6.1
North Central	2.003	24.131	2.370	28.504	2.9
California	4.613	18.920	1.334	24.867	2.6
Pacific Northwest	0.028	13.929	0.000	13.957	1.4
Total	**151.570**	**639.340**	**184.139**	**975.049**	**100.0**

The Gulf Coast region accounts for the most reserve appreciation, or growth, approximately one-quarter of the region's total resources. On a percentage basis, Anadarko and Permian supplies contain the greatest share of resource growth in their respective resource estimates (51 percent and 44 percent, respectively). In contrast, the Rocky Mountain region shows the smallest share of reserve growth (3.9 percent). Being a relatively immature producing region, Rocky Mountain has several areas yet to be discovered. Geologists place resources from undiscovered areas in the potential-resources category.

Natural gas resources in the ground total approximately 975 Tcf, enough to satisfy current consumption trends for the next 50 years. The Gulf Coast has the largest share of total

[2] The U.S. Energy Information Administration provides proven and potential reserve data in its publications *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, Annual Reports.* The California Energy Commission provides the reserve growth estimates.

resources, followed by the Rocky Mountains and the Anadarko region. Together, the three regions account for 65 percent of the total resource. California resources comprise less than 3 percent of the total.

This resource-base estimate is conservative because it is reasonable to assume that a significant portion of Canada's natural gas resource will continue to serve gas markets in Lower 48 states. Canada's resource base totals about 417 Tcf, with Alberta providing the bulk of Canadian production.

It is also reasonable to assume that improvements in exploration and drilling technologies will allow producers to access resources not considered economically recoverable at this time. As a result, prospects for continued expansion of the resource base appear solid.

Natural gas producers extract natural gas from both conventional and unconventional geologic formations. According to data from the U.S. Geological Survey (USGS) and Minerals Management Service, there are 274 Tcf of potential resources in conventional formations and another 365 Tcf of potential resources available from unconventional formations—tight sands, coalbed methane, and shale—in the lower 48 states.

Figure 7-1 shows natural gas production in the lower 48 states by resource type. Energy Commission analysis shows that unconventional sources will satisfy nearly all incremental demand in the future. Thus, although conventional resources can be expected to account for the majority of gas production over the next 20 years, production from unconventional formations will play a significant role. Production of natural gas from coalbed methane formations will increase from six percent in recent years to over 10 percent by the end of the forecast period. **Table 7-2** shows the same production figures by supply region.

Figure 7-1
Lower 48 Production by Resource Type

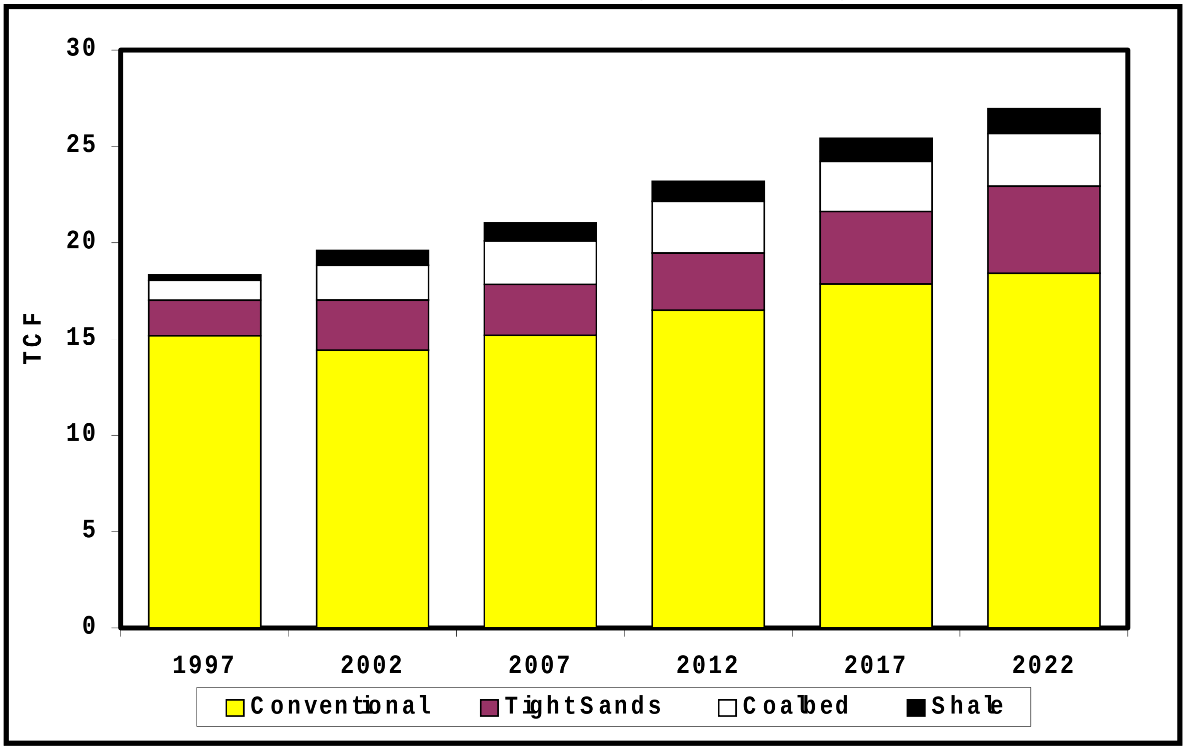


Table 7-2
Lower 48 and Canadian Gas Production (Tcf per Year)

Supply Region	1997	2002	2007	2012	2017	2022
Lower 48						
Anadarko	2.308	2.469	2.405	2.354	2.451	2.172
Appalachia	0.529	0.830	1.031	1.310	1.614	1.879
California	0.297	0.301	0.364	0.374	0.407	0.440
Gulf Coast	10.449	9.497	10.075	11.310	12.556	13.382
North Central	0.258	0.582	0.653	0.740	0.813	0.872
Northern Great Plains	0.200	0.330	0.369	0.425	0.472	0.518
Pacific Northwest	0.001	0.000	0.000	0.000	0.001	0.001
Permian	1.668	1.732	1.743	1.861	1.800	1.712
Rocky Mountains	1.230	1.941	2.341	2.681	3.205	4.004
San Juan	1.403	1.917	2.055	2.130	2.097	1.990
Total: Lower 48	**18.343**	**19.600**	**21.036**	**23.185**	**25.416**	**26.968**
Canada						
Alberta	4.495	5.473	6.065	6.638	6.974	7.135
British Columbia	0.711	0.985	1.043	0.999	1.015	1.026
Eastern Canada	0.000	0.011	0.094	0.124	0.168	0.169
Saskatchewan	0.224	0.268	0.156	0.141	0.123	0.118
Total: Canada	**5.430**	**6.736**	**7.358**	**7.902**	**8.280**	**8.449**

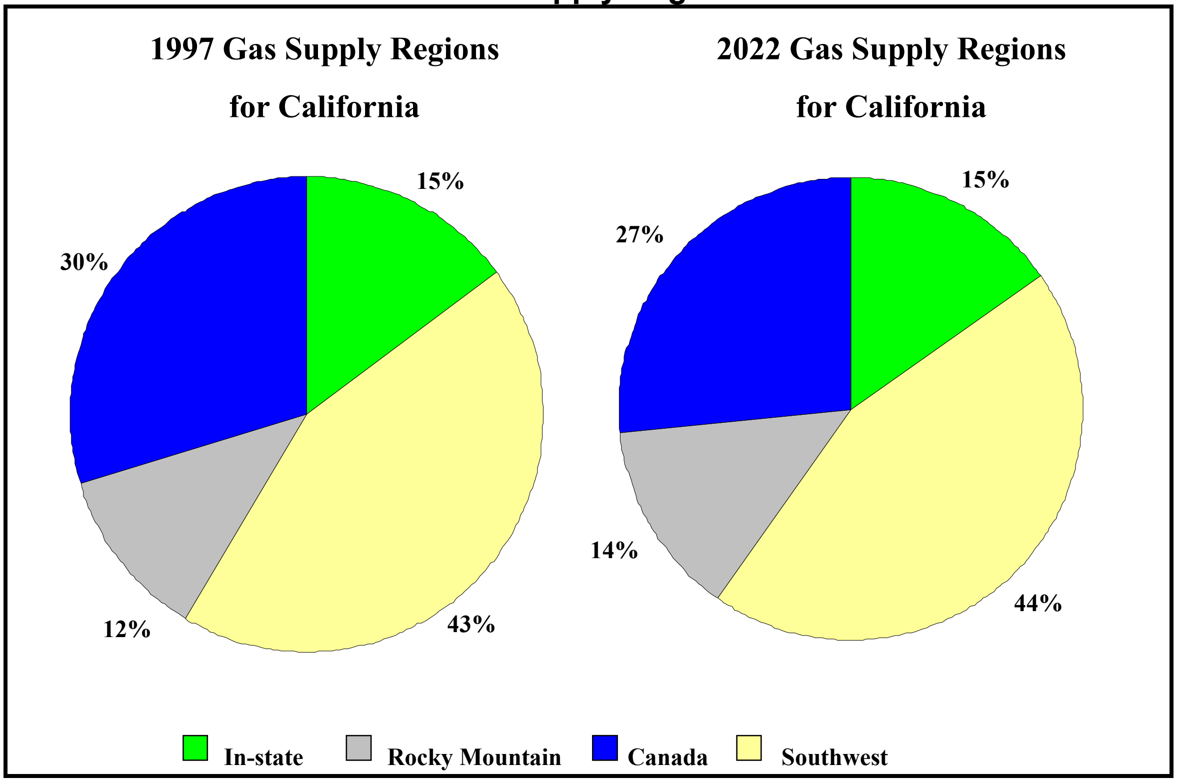
Natural Gas Supplies Available to California

Californians consume between five and six billion cubic feet of natural gas per day (Bcf/d). While the state can contractually receive natural gas from any producing region in North America, given the current pipeline configuration, it can only physically take supplies from four producing regions—the Southwest, the Rocky Mountains, Canada, and California. In-state production satisfies approximately 15 percent of this demand. The remaining 85 percent comes from the San Juan Basin, the U.S. Rocky Mountain region, and the Western Sedimentary Basin of Alberta and British Columbia.

The Energy Commission expects supplies available to California to increase to 7.9 Bcf/d within the next twenty years[3]. No significant change in market share among producing regions is anticipated. Southwest supplies will continue to dominate the California market, holding approximately 44 percent of the market. Canadian producers will supply just over a quarter of the market, with the remainder split between Rocky Mountain and California suppliers. **Figure 7-2** shows the relative market shares in 1997 and expected values for 2022.

[3] The North American Regional Gas (NARG) model, the principal tool used by the Energy Commission since 1989 to assess natural gas market fundamentals and generate the California border price forecast, is a generalized equilibrium model that simultaneously solves for supply and price equilibrium for 18 North American supply and 19 demand regions over a 45-year time horizon.

Figure 7-2
1997 and 2022 Gas Supply Regions for California



The ability of Southwest producers to maintain their share of the California market over the next two decades will be helped to some extent by an emerging gas market in the northern part of Baja California. In July 1997, SoCal Gas completed construction of a 25 MMcf/d pipeline to deliver gas to the city of Mexicali. Additional capacity is expected to be placed into service in conjunction with the completion of the power plant near Rosarito. Given these two expansions, supplies delivered to northern Mexico through California will total 157 MMcf/d.

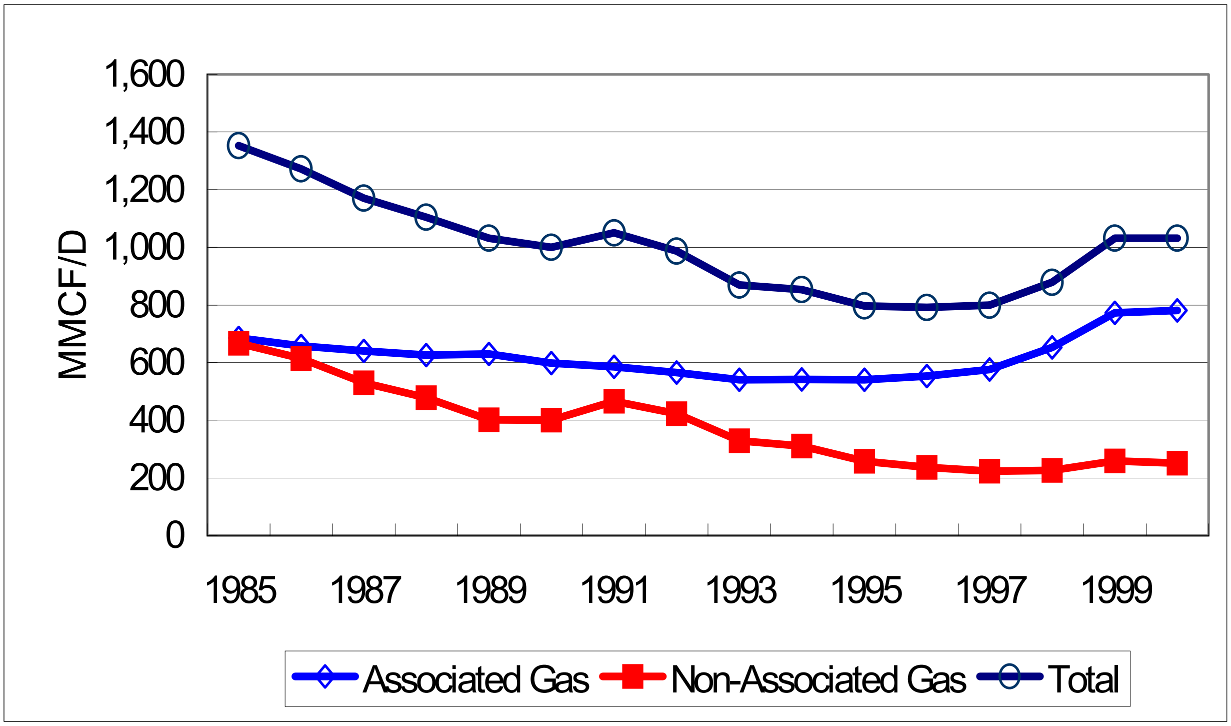
California Natural Gas Production

Southern California produces mostly associated gas while Northern California produces mostly non-associated gas. Nearly three-quarters of California's natural gas production is associated gas. Natural gas produced in Northern California represents about 30 percent of total California production. Offshore production presently accounts for about 10 percent of California's total gas production. Production from the federal continental shelf has been declining for many years, partly due to environmental concerns and related regulations.

Starting in the mid-1980's, California's production experienced a significant decline, mostly in non-associated gas. Production averaged 1,352 MMcf/d in 1985. However, by 1996, in-state production levels had declined to about 800 MMcf/d. Reaching its lowest level in 1996, production has climbed to over 1,000 MMcf/d in 2000.

Figure 7-3 illustrates the trends of California natural gas production. Non-associated gas production has experienced the greatest decline, due mainly to environmental restrictions which limit offshore drilling and production in state waters. However, the Energy Commission estimates that California production will grow over the next two decades, reaching over 1,200 MMcf/d by 2022.

Figure 7-3
California Natural Gas Production



Two gas fields, Elk Hills and Rio Vista, contribute significantly to the recent production increase. Elk Hills, located in Kern County, remains the largest producer of associated natural gas in California. Rio Vista, located in the southern part of California District 6, averaged about 40 MMcf/d of non-associated natural gas in 2000, more than any other dry gas field. In addition, developments in northwest Kern County may provide new resources for California. East Lost Hills, located in this area, may contain 190 Bcf of natural gas[4]. The first well in this field may deliver as much as 10 MMcf/d. Increased production from Elk Hills, Rio Vista, and new areas can positively impact California's market share outlook.

Though holding a locational advantage over gas produced in other regions, in-state gas has lost significant market share over the last ten to fifteen years even as total production has increased. The initial decline in market share was largely due to increased competition at the wellhead and

[4] Berkley Petroleum: Reported in the Bakersfield Californian.

contractual restrictions between producers and PG&E. The contract restrictions precluded producers from gaining access to the spot market. The PG&E Gas Accord Settlements relaxed this situation, and California producers now have the opportunity to market their gas directly to end-users.

In 2000, estimated proven reserves, for onshore and offshore, stood at 3.46 Tcf. Assuming California producers continue to command approximately 15 percent of the California market, the reserve-to-production ratio of proven reserves is 10.3 years. However, in-state market share could change if producers expand their drilling activity as a result of higher natural gas prices.

Pipeline System

Major interstate pipelines bring natural gas from producing regions to California's border where they interconnect with natural gas utility pipelines. **Figure 7-4** depicts the natural gas pipelines in the western United States serving California's natural gas market. **Table 7-3** shows the transfer capability of each interstate pipeline.

Figure 7-4
Western U.S. Natural Gas Pipeline System

In California, there are several utility companies that transport and distribute natural gas to consumers. They include Pacific Gas & Electric Co. (PG&E), Southern California Gas Co. (SoCalGas), San Diego Gas & Electric Co. (SDG&E), Southwest Gas Corp., City of Coalinga, Kirkwood Gas and Electric, Long Beach Gas Dept., and the City of Palo Alto. Other organizations own natural gas pipelines in the State and transport gas to their own customers or use natural gas in their power generation facilities. These organizations include: Washington Water and Power, Sacramento Municipal Utility District, Kern River Transmission System, Mojave Pipeline Company, Shell Western E&P, Inc., Dow Chemical Corp., Tri Valley Oil And

Gas Company, Tuscarora Pipeline Company and the Calpine Power Company. SMUD uses gas to generate electricity and does not distribute or sell natural gas to any customers.

Table 7-3
Interstate Pipeline Capacity And Utility Takeaway Capacity
(MMcf/d)

Interstate Pipelines and Delivery Capacity to California		Takeaway Capacity at California Border		
Pipeline	**Delivery Capacity**	**Mojave**	**PG&E**	**SoCalGas**
PG&E GT – NW	1,833			
El Paso	3,530		1,855	1,990
Transwestern	1,065	400	1,140	750
Kern River	700			
Wheeler Ridge Receipt Point				600
Total	7,128	400	2,995	3,340

Notes:

- PG&E GT - NW delivery capacity to California is impacted by its gas flow into the Tuscarora system. Tuscarora can take deliveries up to 112 MMcf/d from PG&E GT - NW at Malin, reducing California deliveries by up to the same amount.
- PG&E may receive up to 1,140 MMcf/d from a combination of El Paso, Transwestern, Kern River, and Mojave deliveries.
- Mojave receives its supply from El Paso and Transwestern.
- Through Wheeler Ridge SoCal Gas receives gas from California production, Kern River, Mojave and PG&E.
- Not listed, but direct deliveries are made by Kern River, Mojave, and from California production to industrial, electricity generation and EOR facilities

.

Summary

Lower 48 natural gas resources total approximately 975 Tcf, enough to satisfy current consumption trends for the next 50 years. To meet consumption, Energy Commission analysis illustrates that California production will increase currently about 1,000 MMcf/d to about 1,200 MMcf/d. Energy Commission analysis further shows that unconventional sources will satisfy nearly all incremental demand in the future. While conventional resources can be expected to account for the majority of gas production over the next 20 years, production from unconventional formations will play a significant role.

Chapter 8
California Natural Gas Developments

The Energy Commission expects natural gas supplies to remain generally plentiful over the long term. Over this time frame, gas supplies are expected to be affordably priced on average, at levels not likely to alter the relative economics of using natural gas in lieu of other fuels. However, market forces and regulatory events may cause significant short-term fluctuations in natural gas supply and prices, such as those we have experienced during the past year. Pipeline capacity and ability to refill natural gas storage facilities will be constrained over the year, which may limit the availability of fuel supplies to meet seasonal demands though 2001 and early 2002. Current high prices are expected to decline over the next two to three years and will eventually return to long-term trend levels of affordable natural gas supplies.

The Energy Commission expects continued growth in California gas demand, especially for electricity generation. Most new power plants are fueled by gas, contributing to a growing link between natural gas and electricity markets. Furthermore, gas consumption by power plants is volatile since electricity demand may fluctuate significantly depending on weather variations. The long-term outlook for the construction and operation of gas-fired power plants is also uncertain. These uncertainties raise concerns about the future impact of gas prices and supply adequacy on electricity markets.

The Link Between Electricity and Natural Gas Markets

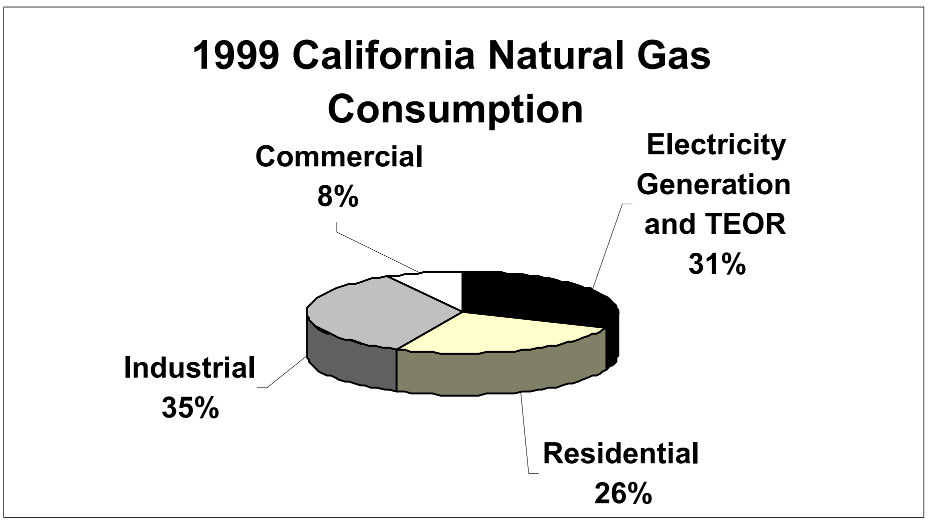
The restructuring of the electricity and natural gas markets has led to an increase in interactions between them. This is perhaps not surprising since the electricity and natural gas markets are responding to similar imperatives: the demand of consumers for high-quality service at the lowest attainable price. Further, electricity and natural gas are considered interchangeable by many industrial and other large energy consumers, to whom energy is simply a means to an end. In fact, most of the largest energy marketers in the U.S. sell both electricity and gas, and willingly alter the proportions of the two as changes in customers' preferences or market circumstances dictate.

Statewide Natural Gas Consumption

California ranks second in natural gas consumption behind Texas. The use of natural gas as a feedstock for the Texas petrochemical industry results in Texas having three times the industrial natural gas use compared to California. During the past six years natural gas demand in California has increased from 5,500 million cubic feet per day (MMcfd) on an annual average basis to 6,100 MMcfd in 1999.

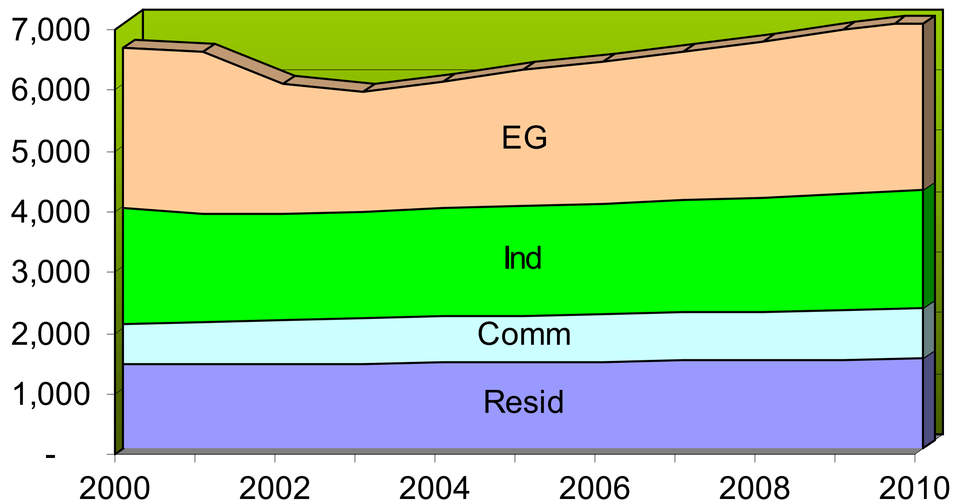
As **Figure 8-1** shows, 31 percent of the 1999 natural gas consumption in California generated electricity and was used for Thermal Enhanced Oil Recovery (TEOR). Most of the California TEOR oil production sites have cogeneration facilities that also generate electricity. Another 26 percent of the gas served the needs of residential customers. The industrial, mining or resource extraction sectors used 35 percent of the total gas use. The commercial sectors consumed the remaining 8 percent. Rough estimates indicate that in 2000 natural gas consumption increased to 6,700 MMcfd, with power generation now accounting about 35 to 40 percent of the consumption.

Figure 8-1



The link between electricity and gas is expected to tighten because all major power plants being built or proposed today in California and much of the rest of the country will rely on natural gas as the fuel. The Energy Commission expects that electricity generation will be the principal cause of increasing natural gas consumption in California over the next decade. **Figure 8-2** illustrates projections over the next 10 years for each market sector in the state. The annual average growth in consumption of natural gas for electricity generation is expected to be about 2.5 percent over the next decade. Although new, efficient power plants will, to some extent, displace electricity generation from older, less efficient plants, total gas consumption for power generation will nevertheless increase over the long term due to growing electricity consumption.

Figure 8-3
Total Natural Gas Consumption by Market Sector



Note: 2000 is actual   Source: California Energy Commission

Table 8-1 shows historical and forecast natural gas consumption for each major California natural gas utility service area — Pacific Gas &Electric (PG&E), Southern California Gas Co. (SoCalGas), and San Diego Gas and Electric (SDG&E). The data shown in **Table 8-1** exclude natural gas used in the production of electricity.

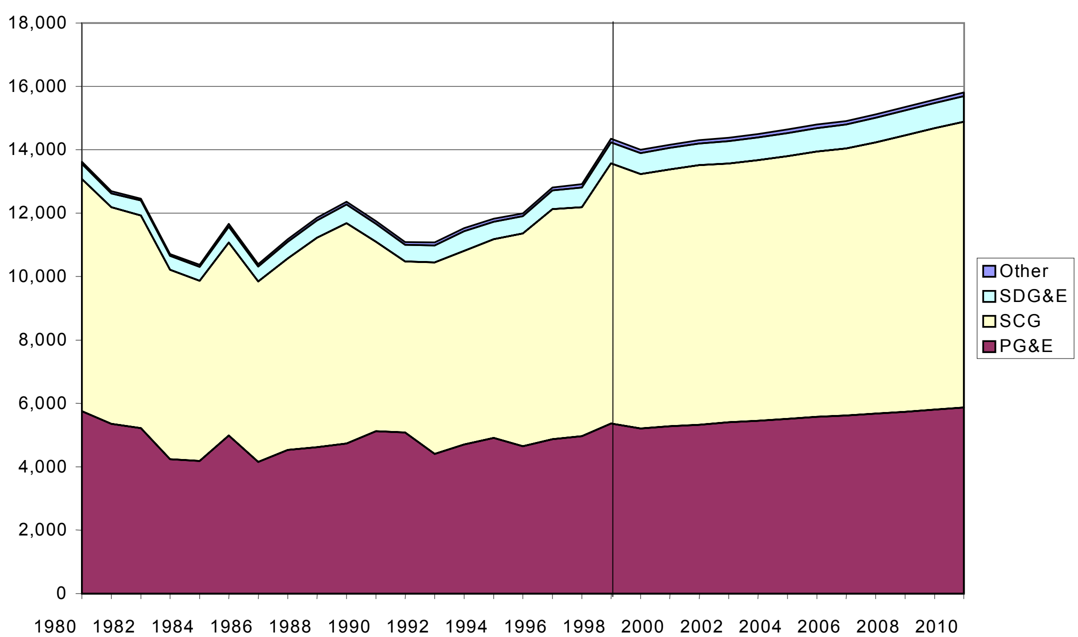
Figure 8-3 shows the historical and projected natural gas consumption trends for each utility region. End-use natural gas consumption dropped by an average 1.5- percent annually in the 1980s followed by average annual increases of 2.5 percent in the 1990s. Over the next 10 years, the Commission expects natural gas use to increase at a rate of 0.8 percent per year. Residential natural gas use in 2010 will be at approximately the same level as in 1998 due to the impacts of various natural gas energy efficiency programs. These programs include building and appliance standards, and utility energy efficiency programs. Commercial and industrial gas use is expected to grow at just over 1.0 percent per year.

Table 8-1
California Natural Gas Consumption by Utility Service Area
(Millions of Therms)

Year	PG&E	SoCalGas	SDG&E	Other	Total State
1980	5,752	7,328	470	78	13,627
1990	5,122	5,976	556	95	11,748
2000	5,274	8,106	673	102	14,155
2010	5,863	9,020	806	112	15,802
Cumulative Growth (%)					
1980-90	-11%	-18%	18%	22%	-14%
1990-00	3%	36%	21%	8%	20%
2000-10	11%	11%	20%	9%	26%
% per yr					
1980-90	-1.15	-2.02	1.69	1.99	-1.47
1990-00	0.29	3.10	1.93	0.71	1.88
2000-10	1.06	1.07	1.82	0.94	1.11

Source: California Energy Commission Staff, California Energy Demand 2001- 2010. (10 Therms is approximately equal to 1 thousand cubic feet of gas.)

Figure 8-3
Natural Gas Consumption by Utility
(Millions of Therms)



Source: Energy Commission Staff

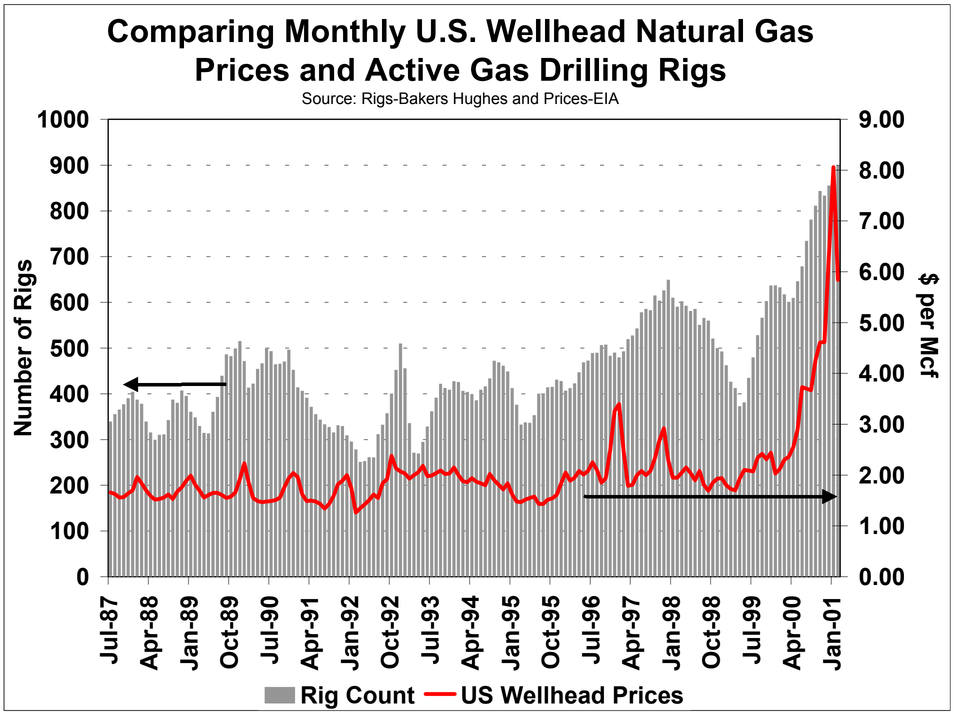
Natural Gas Prices

The price of natural gas to consumers is composed of the price for the commodity plus the cost to deliver the gas to the consumer. The natural gas commodity market is highly competitive while the transmission and distribution charges are regulated, mostly at cost-based rates. The net effect is prices to consumers that reflect market conditions.

The Energy Commission natural gas price forecasts are developed considering a long-term market perspective, on an annual average basis. Gas resource availability and commodity and transportation costs are the main drivers in this analysis. The Commission expects that future gas prices will oscillate due to shifts in supply availability, demand fluctuations, and regulatory changes. Market forces will tend to correct the causes of the price excursion and bring prices back toward a long-term trend. Still, temporary price spikes will tend to generate high levels of concern throughout the market. In addition to price spikes, low price levels are worrisome. Low prices block investment incentives for natural gas producers to purchase additional production capacity or hire more labor to produce natural gas. During 1998 and 1999, the gas market experienced this situation that resulted in supply unable to grow at demand's growth.

Recent natural gas spot market prices have considerably exceeded the long-term price trends, based on several factors. First, increasing natural gas demand, particularly in power generation, has apparently outstripped production. This is because natural gas prices over the past decade have been at low levels. The low prices have not provided the economic incentive for producers to drill enough wells to produce sufficient natural gas supplies to meet the growing demand. For the past 10 years there was only a monthly average of 454 rigs actively drilling for natural gas, which is not sufficient to maintain supply. Many in the industry feel that from 600 to 800 active drilling rigs are necessary to sustain wellhead deliverability to meet demand. **Figure 8-4** shows that drilling activity has picked up significantly this past year. Beginning in April 1999, average wellhead prices in the U.S. began to climb and drilling activity followed. By the first of January 2001 active rig count had risen to 862.

Figure 8-4



The second factor affecting recent gas prices is the lack of economical fuel alternatives. Even though natural gas prices have increased over the past year, minimal switching to other fuels has occurred because alternate fuel prices, such as fuel oil, have also risen to comparable levels as natural gas. In California, burning oil for power generation is restricted to only a few power plants and only under the most extreme conditions. The impact of these high gas prices has resulted in potential reduction in demand in the fertilizer, paper, aluminum, and nursery industries, which uses natural gas as a feed stock. Finally, an August 2000 explosion on one of the pipelines delivering Southwestern U.S. gas to California, at a time when gas supplies were already tight, further stressed the gas delivery system. Gas prices at the California border took another jump.

The third factor is that interstate and in-state pipelines have been running full. As the interstate pipelines continue to have little spare capacity there is little price competition between interstate pipeline operators. In addition, California natural gas utilities are operating at or near their maximum capability to receive natural gas from the interstate pipelines delivering to California. Consequently, parties wanting natural gas have to outbid other potential procure natural gas. These strains on the system and behavior of market participants contribute to high natural gas prices.

The Energy Commission's recently published report titled *Natural Gas Infrastructure Issues* (Publication #P200-01-001A, August 2001) was published in response to high prices and constrained gas infrastructure. Natural gas market participants currently have plans to improve the natural gas infrastructure. These improvements will help to assure that

California has adequate supplies of natural gas to mitigate the current high natural gas prices that California is experiencing. The Report raises emerging natural gas infrastructure issues that should be watched closely to assure that infrastructure improvements are coming on-line as planned. This should provide an early warning of developing problems so that the industry and government can take actions to prevent shortages or ameliorate adverse consequences

Fortunately, current high gas prices are not expected to last indefinitely. As indicated above, gas producers have reacted to recent higher gas prices and are striving to increase production. However, it takes considerable time to increase production to the required levels. It is anticipated that with sustained higher drilling activity, natural gas production capability will be in balance with demand in two to three years. By that time natural gas prices should return to the long-term, cost-based price trend. The Energy Commission staff is in the process of conducting the long-term natural gas supply and price forecast, which should be released by Fall 2001.

Gas Supply Adequacy

North America has a huge base of natural gas resources to serve long term needs. This resource base can provide affordable natural gas supplies to serve the nation for the next 50 years at current demand levels. Liquefied natural gas (LNG) is another economic natural gas supply source. LNG imports, while currently relatively small, have been gradually building in recent years and are expected to continue expanding. In addition, there are "unconventional" natural gas resources (such as natural gas hydrates and geopressured brines) that are currently not economical to produce. These additional supplies represent a potential resource that significantly exceeds the amount of conventional natural gas resources.

Concerns about supply meeting demand for the short term foreseeable future is measured by the availability of existing gas resources, plus the capability to produce and deliver additional supplies. Expanding gas production and delivery capability requires large amounts of capital and lead times that can stretch into several years. As a consequence, supply and demand can temporarily be out of balance, resulting in short-term problems. The resulting supply may be tight or there may be a surplus. This cyclical "boom-and-bust" nature is common to many large, capital-intensive industries in a market economy.

The adequacy of the North American pipeline network to deliver gas to California is critical. About 85 percent of the gas consumed in the state is imported from outside California including Canada. Growing gas consumption, together with the increasing dependence of electricity generation on gas as a fuel, is raising concerns about the adequacy of in-state utility and interstate gas pipeline capacity to deliver needed gas supplies to California. Concerns focus on the ability to deliver gas during peak demand days, which can occur during summer heat waves (to generate electricity for air conditioning loads) or winter cold spells (due to space heating requirements). Concern also exists for the lack of gas competition as pipeline capacity is fully consumed. Without excess pipeline capacity, prices may exhibit extraordinary volatility and price spikes.

Interstate gas pipeline capacity currently appears adequate. However, Energy Commission long-term studies show that more interstate pipeline capacity is needed within the next two to five years to deliver gas to California and meet the expected growth in daily demand. Episodes of unusually severe weather (whether hot or cold) can cause temporary gas delivery problems sooner, but such conditions are unpredictable. The largest and most pressing pipeline capacity shortages over the 20-year forecast period will arise from the Rocky Mountain supply area, where capacity shortfalls could occur as early as 2002. Another area of concern is with the PG&E Gas Transmission line bringing Canadian supplies to Northern California. New gas demands from power plants being built along that pipeline's route may reduce the ability to deliver gas to California.

Within the state, the future ability to deliver adequate gas supplies to the SDG&E service area is of particular concern. The pipeline infrastructure in this area is approaching the limits of its capability to deliver gas to meet growing demand. The situation in San Diego is compounded by the fact that since June 2000 SDG&E started delivering natural gas to Mexico to meet power generation gas demand at the Rosarito Beach facilities. Further, the proposed Otay Mesa gas-fired power plant near San Diego could begin operation in 2002 or 2003.

Energy Commission staff examined the capability of gas pipelines in the SDG&E area to meet peak summer gas demands in 2002 and 2005 under a variety of scenarios. These scenarios assume different electricity system operation and gas supply conditions. Staff found a *potential for gas curtailments due to inadequate delivery capability in all cases examined, even in the near term*. The pipeline delivering natural gas from the SoCal Gas system to the San Diego Gas and Electric Company system (Line 6900) has been expanded by about 70 MMcfd and is in operation today. However, the anticipated increase natural gas demand for power generation in SDG&E area and in Mexico could potentially outstrip this expansion. The potential curtailments in 2005 could be avoided by constructing additional pipeline capacity. Major additional capacity currently in the early stages of development would be available after 2003.

Need for "Slack Capacity" on Interstate and Intrastate Pipeline System

There is evidence that high prices are due to a constrained pipeline system. As observed at the California border, the pipelines have been operating at their maximum capacity conditions. A 'Slack Capacity' is defined as the amount of pipeline capacity that should be maintained in excess of the demand to generate the benefits of competition (footnote or end note: CPUC Decision 97-08-055). When there is no slack capacity, customers lose the benefit of competition, resulting in overall price increases or upward spikes. The Energy

Commission in its above mentioned Report, recommends that a 15 to 20 percent slack capacity be maintained to mitigate the extreme volatility observed in recent market transactions.

Natural Gas Market Infrastructure Proposals

Natural gas regulatory reforms over the past two decades have created a situation where market forces can generally be relied on to provide additional pipeline capacity when needed. Indeed, several proposals by private and utility companies to expand or build new pipeline and storage capacity to serve California markets are currently being pursued.

Interstate Proposals

- Questar, a pipeline company that operates in the Rocky Mountain region, has received Federal Energy Regulatory Commission (FERC) approval to convert the Four Corners Pipeline to transport natural gas rather than crude oil. The pipeline extends from the San Juan Basin of Colorado and New Mexico to Long Beach, California. The pipeline is expected to be operating in early 2002 although initially it may deliver gas only as far as the California border.

- Kern River Pipeline Company filed with the FERC in late 2000, an application to expand the capacity of its pipeline from the Rocky Mountains to the Bakersfield area. The project provides an additional 135 MMcfd and is now online. Another request for further expansion has been filed by Kern River in mid-2001, to increase the capacity by an additional 900 MMcfd.

- El Paso Natural Gas Co. purchased the All American Pipeline, a crude oil pipeline extending from Santa Barbara, California to Texas. El Paso has received FERC approval to convert the pipeline to transport 230 MMcfd of Southwestern U.S. natural gas to the California border.

- A consortium of American and Mexican utilities proposes to build the new North Baja Pipeline to deliver Southwestern U.S. gas to Tijuana, Mexico via Arizona and Mexicali. This pipeline would not only remove or greatly lessen the pressure on the SDG&E system to deliver gas to Baja, Mexico, but could potentially provide an additional source of Southwestern gas to San Diego via Baja. It could be operational in late 2002 or early 2003.

Instate Proposals

- Pacific Gas & Electric - Gas Transmission Northwest (PG&E-GTN) has proposed several expansion projects over the next 2 years to increase the supply of Canadian gas coming into California by about 200 to 400 MMcfd.

- Two interstate pipelines, the Ruby Pipeline by El Paso Energy Company and the Sonoran Pipeline by the Kinder Morgan Company, are being proposed to bring 750 MMcfd or more of natural gas from the Southwest supply basins. These pipelines are anticipated to be in operation by 2003.

- SoCal Gas has proposed specific expansion projects to increase the in-state capacity to transport gas from the state border by about 350 MMcfd. In addition, SoCal Gas has received approval by the CPUC to abandon the Montebello storage facility, releasing the 12 billion cubic feet of stored gas (at a maximum withdrawal rate of 50 MMcfd). Also, SoCal Gas is approved to increase withdrawal rates from the Aliso Canyon / La Goleta storage facilities by an additional 90 MMcfd.

- PG&E Company is considering plans to expand the existing pipelines from both Malin (Canadian supplies) and Topock (Southwest supplies), in the range of 200 MMcfd to 400 MMcfd.

- Wild Goose, a private storage facility operator is proposing to expand their storage facility in Northern California from the current 14 Bcf to 29 Bcf. Another private storage facility, the Lodi Gas Storage is anticipated to be in operation during 2002, enhancing the capability to serve the consumers in the state during peak demand periods.

Natural Gas Storage Facilities

Natural gas utilities typically rely on stored natural gas to augment flowing pipeline supplies to meet total natural gas demand throughout the year. A natural gas system designed to meet the peak demands that does not include the ability to draw on storage would cost significantly more than the current system. Relying on pipelines to supply total demand would result in substantial amounts of unused pipeline capacity during the year. The lack of pipeline utilization would not generate sufficient revenues to cover investments in pipelines and related facilities.

Consequently, California's existing natural gas pipeline system is designed to meet peak demands by drawing on additional natural gas supplies from storage facilities. Without storage, the gas utilities would be unable to supply natural gas needs. In California, storage is essential to meet peak natural gas demand, which is typically in the winter heating season. Currently, with increased natural gas demand for power generation in the summer season, storage is being used to augment pipeline flowing gas to meet the peak demand. This drawdown will impact the ability of utilities to store sufficient gas for the regular winter heating season.

The storage system in California is primarily located close to California metropolitan areas. **Figure 8-5** shows the location of underground storage facilities in California. The figure also shows the storage capacity, maximum injection and withdrawal rates for PG&E, SoCal Gas, Wild Goose and Lodi Gas. Wild Goose and Lodi Gas are privately owned storage facilities. The storage facilities are depleted oil and gas fields that have been modified to allow both injection and withdrawal of gas.

SoCal Gas intends to modify its Aliso Canyon and La Goleta storage fields. This would add 14 Bcf in storage for winter 2001-2002. The modifications would shift gas currently used to maintain pressure in the storage field to gas available for withdrawal. SoCal Gas will also have available 10 to 12 Bcf from the abandonment of the Montebello storage facility. However, once withdrawn this storage facility will be closed and no longer be available to store or withdraw gas. It is expected that this gas may be available during the summer 2001.

As mentioned earlier, a private entity is developing the Lodi Gas storage facility in Lodi, California in the PG&E service territory. This facility will add 12 Bcf in storage capacity to northern California. Recently, Wild Goose storage facility announced its plan to expand storage capacity from 14 Bcf up to 38 Bcf. In addition, withdrawal capacity would increase from 200 MMcfd up to 650 MMcfd. This expansion will provide significant inventory to meet peaking demand.

Historically natural gas injection into underground storage facilities begins in the spring and continues though the fall months when gas demand is at it's lowest. A limit to placing gas into storage, besides injection capacity, is the availability of unused pipeline capacity. Unused pipeline capacity is generally available after winter demand has dropped to lower levels. Spare pipeline capacity is usually available in the spring and fall and on low demand days in the summer.

If sufficient gas is not injected into storage during periods of low demand, stored gas cannot be used to supplement deliveries of natural gas from interstate pipelines to meet higher peak demands. Due to high demand for natural gas in the spring and expected in the summer of 2001, gas utilities may not be able to inject sufficient natural gas into storage to carry California customers through next winter's peak heating season. In addition, if electric generators and industrial customers do not place gas into storage prior to the summer electric peaking season, curtailments of these loads could exacerbate electricity shortage conditions and lead to additional blackouts. A complete analysis of storage issues is located in the California Energy Commission's study, *Natural Gas Infrastructure Issues*, to be published in summer 2001.

Figure 8-5
California Storage Facilities

Loss of Oil-Burning Capability at Power Plants

As mentioned earlier, natural gas use is highly temperature-dependent due to winter space-heating demand and summer gas-fired power generation for air conditioning. During extreme weather conditions gas demand can exceed the capability of pipelines to deliver gas from the major out-of-state supply areas. The response has been to store gas in underground fields near the major consuming areas and withdraw it to supplement supplies during peak demand periods. Even so, during exceptional demand periods gas supplies may be inadequate to serve all potential demand.

The traditional response has been to curtail gas delivery to some or all power plants and large industrial facilities, which switch to burning oil during those brief, infrequent periods. This practice has long been considered normal and acceptable. Because peak gas demand periods are infrequent and of short duration, it would not be economically rational to build the gas supply system (pipelines plus underground storage) to meet all potential demand 100 percent of the time.

Electricity restructuring, however, is partially undermining this system. The private companies that purchased the fossil-fueled power plants once owned by California's investor-owned utilities have no regulatory obligation to maintain oil-burning capability. Many of them seem to be making the business decision that it is better to cease generating electricity during brief gas curtailments than to bear the expense and environmental liabilities of maintaining oil-burning capability. That decision raises unanswered questions regarding its effect on electricity reliability. Could electricity reliability be threatened by power plant fuel shortages during extreme peak demands for natural gas?

The Independent System Operator (ISO) led a multiparty study (including the Energy Commission) of this issue to quantify the risks and investigate possible options to mitigate the risks. The study concluded that certain identified power plants that are critical to maintaining electricity reliability in California are at risk of experiencing inadequate gas supplies during very cold weather. The study further concluded that increasing the dependability of underground gas storage for those critical power plants is a preferred option to alleviate the risk, when feasible. It is infeasible for some of the critical power plants, because of their remoteness from underground gas storage facilities. As of October 2000, the ISO was pursuing ways to assure the required reliability during cold periods by contracting with generators to obtain adequate firm gas storage. In addition, the ISO has contracted to cover the cost of oil backup for those facilities lacking access to gas storage.

Another avenue to explore in addressing the risk to electricity reliability due to curtailed gas supplies is possible revisions to the CPUC's gas curtailment rules. These rules were devised at a time when curtailing gas to power plants was not a reliability risk because the plants could switch to oil. If that is no longer the case, it seems appropriate to revisit the curtailment rules. The impacts of such curtailment cross several regulatory boundaries. Coordinated efforts between the CPUC, Energy Commission, ISO, California Air Resources Board (CARB), and Air Pollution Control Districts (APCD), as well as the utilities and other affected customers, should be established. Each of these entities has a responsibility or interest when natural gas service is interrupted. The CPUC regulates the utilities and, as such, is responsible for overseeing the rules under which the utilities operate. The ISO is concerned about the potential loss of generation capacity and the resulting impact on electric system stability during very cold or hot weather conditions. The CARB and the APCDs are concerned with power plant emissions. Utilities have to administer the rules and other parties may be directly impacted by the rule administration.

Summary

The Energy Commission expects continuing growth in California gas demand. There is evidence that current gas infrastructure is constrained as it operates near maximum capacity. In the long term, market forces can be relied on to provide additional gas infrastructure to meet future needs. As outline in the *Natural Gas Infrastructure Issues,* the Energy commission will closely follow the gas market to provide an early warning of any infrastructure improvements and development issues.

Appendix A

Increasing Demand Responsiveness in Electricity Markets

Introduction

In a competitive market, both suppliers and consumers are able to see and respond to prices. A key element that government regulators and industry analysts now agree has been missing from California's electricity market design is demand responsiveness – consumption that varies according to market prices. Legislators, policy markers and market participants agree that greater demand responsiveness is essential for four principal reasons:

- To allow consumers to pay for the electricity they want and not for electricity which is too expensive
- To lower costs for everyone by reducing peak demand and hence the very high prices which are paid for marginal, inefficient supply when demand peaks
- To allow the market to reach a stable equilibrium between demand and supply and avoid rotating outages
- To allow both consumers and energy service providers to select the manner of managing price risk which meets individual needs.

The ability to respond varies among end-use consumers, and several different types of programs are necessary for demand responsiveness to be effective.

Historically, there has been little need for demand responsiveness. Most consumers faced rates that provided broad signals about the annualized cost of electricity. At the most there was a seasonal differential. These prices did not reveal the huge swings in hourly prices from early morning to late afternoon, or the short-term price spikes and valleys which can happen quickly as weather, availability of generation, or transmission congestion cause daily market prices to rise or fall. Consumers did not have the knowledge, ability, or incentive to change their electricity use quickly. There were limited numbers of interruptible programs that served as a last resort to avoid outages stemming from supply-side equipment failures.

Unlike the past, a competitive electricity market needs some consumers to change their uses quickly. The market also needs all consumers to invest in the equipment and behaviors that will manage their electricity use and their exposure to the risks of price volatility. Demand responsiveness does not mean consumers should swelter in the summer because air conditioning costs too much, or that businesses should send employees home because a production run must be terminated. California must develop demand responsive programs that meet the different needs of consumers and introduce discipline into the market without inflicting hardship. While full changes will emerge over several years, we must achieve significant progress by this summer if the market is going to function in an acceptable manner.

Under the restructured industry's initial market rules, the highest accepted price bid set the price for all suppliers and all loads. When supplies were scarce, the supply side of the energy market was able to submit increasingly high generation bids that are unchecked by reductions in load bids. The result was price spikes. This possibility turned into horrifying reality during the summer of 2000. With the rate freeze lifted, SDG&E customers were exposed to unexpected high prices with little advance warning, no effective education about how to minimize bill increases, and minimal opportunities to effectively respond. When the summer's price spikes appeared in the bills of San Diego customers, we did see some price response. Extraordinary awareness of electricity prices and the consequences for consumer bills was developed through media publicity. But, this was a response to an emergency situation and is not an efficient or fair burden to place on unprepared consumers.

As a response to the California Energy Crisis that began last summer, and which has continued unabated for nearly a year, many changes in the responsibilities of industry participants have been made. Even though the Power Exchange is now defunct, and UDCs were freed of their obligations to exclusively buy from/sell to the PX, there is still an active bilateral contract market. Electricity prices are not nearly as transparent as they were when the PX existed, but the level of demand relative to available supply still influences market price. In addition, California faces a reliability problem because supply has not kept pace with demand. Thus, for cost containment reasons and reliability reasons, increasing the level of demand responsiveness has become an important goal of energy policy makers.

The Energy Commission has decided to play a specific role with respect to demand responsiveness related to our unique position in monitoring the overall level of supply and demand and our statutory responsibility to ensure electricity reliability. Rather than be a program delivery agent for demand responsiveness, we have encouraged other agencies to act within their own jurisdictions to collaboratively achieve the levels of demand responsiveness that we believe the market requires. In addition to this coordination role, the Energy Commission wants every consumer to make an informed choice about the use of power using both its cost and their own unique value for the services electricity provides. A key element guiding these choices is the market price of electricity. When these choices are aggregated, they will help the market finds its natural balance between supply and demand. Rate designs that encourage such responses will be feasible due to new communication equipment, controls and software that allows for rapid assessment and response. In addition, a mix of programs is necessary to meet different consumer information and value profiles due to the limitations on the pace of deployment of the advanced technologies that consumers need to fully respond on the basis of market prices alone.

This Appendix is an overview of efforts to increase demand responsiveness. Current efforts focus on utility load curtailment programs, ISO efforts to achieve greater load participation in its markets, and initial efforts to improve demand responsiveness at a more systematic level using interval metering, the response of end-users, and how to incorporate, for planning purposes, the projected impacts within demand forecasts. The section concludes with recommendations for action by the Energy Commission and other agencies.

Why Consumers Don't Respond to Real Prices

When the price of a product goes up, consumers may choose to buy less or shift to a substitute. They may choose to buy a lot less (elastic demand) or only a little less (inelastic demand). Currently, electricity demand is very inelastic with respect to wholesale market prices. Consumers do not reduce their hourly purchases of electricity by much when the hourly price of producing the power skyrockets because very few see the hourly wholesale price of power and it does not affect their bill[1]. Demand responds in this way because consumers have neither the motivation nor the means to respond.

First, consumers have no **motivation** to respond because a rate freeze means that the rate for power is held constant for 24 hours a day even though actual costs may vary by a factor of 10 or more. Seasonal electricity rates provide a crude price signal to end-users. These typically revised rates up by 2-3 cents per kWh in the summer. The price fluctuations from market pricing are much different. On spring days in 1999 prices ranged from 0 to .21 cents per kWh. On June 29, 2000 prices ranged from 5.2 cents to 91.2 cents per kWh. In February 2001 prices clustered around 32.5 cents per kWh. None of these recent patterns of market prices influenced consumer behavior because the great majority of consumers were insulated from such prices by rate freezes imposed by the legislature. Even the larger consumers in SDG&E service area cannot reduce their costs by shifting load from expensive on-peak hours to cheaper, off-peak hours. They pay based on a set load profile for their class, not based on their own daily pattern of use.

Second, consumers have virtually no **means** to respond because:
- Consumers must be informed of the hourly wholesale price to enable them to evaluate whether to adjust their consumption.
- Interval metering technology must be installed to allow consumers to monitor and ultimately experience the costs of their individual patterns of electricity consumption.

To respond to market prices, consumers must know what those prices are in time to act. Discovering prices long after the fact, as SDG&E bundled service customers did in June 2000, is totally ineffective and unacceptable. Consumer also must have the technology to

[1] The overall rate freeze is still in effect for PG&E and SCE, the AB 265 rate freeze has been in effect for SDG&E residential and small commercial customers since September 2000, and AB1x-43 imposes a similar rate freeze for larger SDG&E customers as of March 1, 2001. But, the high costs are still being charged by generators to UDCs (and since January 2001 to CDWR) and held in a balancing account. Depending on the outcome of the CPUC's investigation, FERC decisions to order rebates from generators, the PG&E bankruptcy outcome, and the legislature's decision to accept Governor Davis' efforts to buy utility transmission systems, end-users may ultimately pay some or all of these energy costs.

modify their electricity use when the cost of power is more than its value to that individual consumer. To be convenient, this probably requires widespread penetration of programmable, price responsive controllers and other devices that control appliances through simple decision rules entered by the consumer. In time, consumers or their energy service providers need to have their energy usage patterns reflected in their actual bills. Many end-users will require interval metering equipment and low cost techniques to read these meters.

How Demand Responsiveness Could Work

Communication of electricity prices and recognition of high prices by consumers will affect how much demand responsiveness occurs. Most end-use customers cannot support any substantial overhead burdens in tracking and digesting prices to selectively shift/not shift loads. This suggests the need for:

- Automatic telemetry equipment to disseminate prices;
- Dedicated telemetry paths, such as through metering data retrieval systems, instead of generic pathways such as the internet;
- Programs that simplify decisions for customers to reduce transaction burdens, such as interruptible programs in which the customer signs up in advance to be interrupted under given conditions; and
- Electronic processing algorithms and *in situ* appliance controllers that respond to price signals using preset decision rules.

Achieving greater hourly demand responsiveness does not require the participation of all end-users. Because the price curve is very steep at the top end, the load reductions induced by the demand responsiveness of some end-users result in reduced market clearing prices for all participants whose energy costs are linked to the wholesale market. During the initial investigation of demand responsiveness in the spring of 2000, researchers discovered that in historic hours where prices had been very high, just a three percent reduction in loads resulted in a 25 percent reduction in the market clearing price of electricity. We expect that this kind of response is still valid even though the demise of the PX makes determining such results more difficult.

It is also not necessary for every consumer to pay highly variable bills. Some consumers may prefer level payments, and so may choose to have their energy service providers absorb the risk that prices will vary sharply on a daily basis. Once SDG&E end-users began to receive high bills in June 2000, some ESPs began actively marketing direct access contracts that provided levelized payments.

Activities Underway to Increase Responsiveness

Both near-term and long-term efforts are needed to increase demand responsiveness. For the near-term, programs are being designed and implemented to achieve some degree of demand responsiveness for 2001 and 2002. Price-responsive load bidding into the forward markets will be operated by utilities to counter generator and power supplier market bids. The ISO has modified its ancillary service bidding rules to permit loads and distributed resources to participate more cheaply. Load shedding and other interruptible programs organized directly by the ISO, and also through UDCs, for those customers who chose to participate will be part of emergency response processes conducted by the ISO when reserves fall below WSCC-required margins.

For the long-term, more systematic and inclusive changes involving new rate design must be implemented. This category will take longer to implement because of the necessity to deal with huge number of end-users, but it will ultimately supplant the near-term activities. These efforts include:

- Rate design to communicate financial consequences of wholesale prices to end-users;
- Electronic telemetry to permit customers to receive the prices; and
- Interval metering which allows bills to reflect the end-user's actual pattern of consumption, rather than a broad class profile.

The Energy Commission has supported utility load curtailment and price responsive programs at the CPUC and urged the ISO to develop its own programs that can permit loads to participate in existing or new ancillary service markets and load curtailment programs. We have frequently urged the CPUC to develop requirements for interval metering that will result in broad scale exposure of end-users to the hourly commodity energy pricing decisions already included within D.00-06-034.[2] Central to these rate design approaches is the issue of how interval metering and electronic telemetry will be deployed. Currently the CPUC has not resolved whether metering will remain the exclusive activity of the UDC as it always has been for bundled service end-users, or whether it can be opened to competition as it now is for direct access end-users. Until this uncertainty is resolved, UDCs will be reluctant to make the investment, or long term commitments with outsource vendors, needed for these systems.

Programs During the Summer of 2000

All three investor-owned utilities initiated voluntary load curtailment programs that introduce a degree of demand responsiveness during the summer of 2000. As approved by the CPUC, SCE and PG&E would have been able to curtail 500 MW of load when market

[2] On April 13, 2001, the CEC filed rate design testimony at the CPUC recommending implementation of a real-time price supplemental agreement, modeled on the Georgia Power experience with RTP programs, that would augment the base tariff that will be decided in the Rate Stabilization proceeding.

clearing prices exceed $250 per MWh. Unfortunately, low customer participation prevented these programs from achieving their authorized potential.

The ISO encouraged greater demand responsiveness for some of the ancillary services markets by making it easier for end-use loads to participate in ISO ancillary services markets and by creating a new Demand Relief load curtailment program that was triggered by A/S prices. The ISO has temporarily reduced the requirements for participation in the non-spin and replacement reserve markets to lower costs of participation hoping this would encourage greater participation. Unfortunately, like the utility programs, neither of the ISO Summer 2000 programs achieved customer participation goals.

The largest existing demand responsiveness program is the utility interruptible rates. It was operated by the ISO nearly 20 times during summer of 2000, for a maximum savings of over 2,000 MW on August 2. This is far beyond the expectations of program participants and many southern California customers exercised their contract right to pay a penalty instead of interrupting their demand. Because of this widespread non-compliance, the CPUC initiated R.00-10-002 to investigate program performance. As an initial action, the CPUC issued an order suspending the contractual right of participants to opt-out pending further review. Finally, consumer awareness and voluntary load reduction programs were put in place to induce end-users to reduce loads during system emergencies or to forestall involuntary load shedding. The ISO made public appeals when temperatures are high and supplies are short. For example, members of the California Grocers' Association reduced their peak use by 100 MW in response to ISO appeals. The State developed and implemented voluntary load reduction programs that were operated on several critical days, with estimated savings of 180 MW.

All of these summer 2000 program activities, both successes and failures, were useful in determining how to achieve the greater levels of participation that we believe are needed for summers of 2001 and 2002. Unfortunately, the orderly examination of programs and design or new ones has been constrained by the crisis atmosphere engendered by the extraordinarily high levels of wholesale market prices that began in June 2000 and that have persisted to this day despite efforts to control or moderate them.

Future Programs

As a result of the necessity to act on many fronts to reduce market prices and continuing concern over system reliability, the legislature, regulatory agencies and the ISO are attempting to develop and implement new programs for summer of 2001.

The CPUC's rulemaking on interruptible programs reviewed existing interruptible rate designs and the development of expanded versions of UDC load curtailment programs that were tested in summer 2000. D.01-04-006 created a wide range of new load curtailment programs, revised existing interruptible rate conditions, allowed opt-out from these interruptible rates for those participants intolerant of likely levels of interruption, and carefully examined involuntary outage programs that are likely to be needed during summer of 2001. Unfortunately, in an effort to reduce total energy expenditures, the CPUC directed UDCs to track program expenditures for possible future recovery rather than providing a direct source of new monies. As this writing, UDCs have filed petitions for modification arguing that they cannot sustain the cash flow burdens of operating these programs without new sources of funding.

Anticipating the need for much expanded demand responsiveness, the ISO began its program development efforts in the fall of 2000 by proposing expansion of its Demand Relief (DR) program and development of a new Discretionary Load Curtailment Program (DLCP). The ISO accepted 596 MW of bids in February for its DR program and is now in the midst of a second round of solicitations for more participants. This program resembles the UDC interruptible rate program in that it includes a fixed reservation payment ($20 per kilowatt-month for each of the summer months) in return for a firm commitment to curtail when called just before involuntary load shedding. Unlike the interruptible programs, actual load curtailed is paid $500 per megawatt hour. The DLCP pays only $350 per megawatt hour of energy curtailed, but offers complete freedom to interrupt as the end-user sees fit. Both of these programs use the concept of a load aggregator to serve as an intermediary to conduct the marketing and data collection/verification activities of the program.

Working with Energy Efficiency Public Good Charge funds, the CPUC is in the process of focusing concern on near term peak demand impacts in addition to long term market transformation. Reprogramming some funds carried over from 1999 has been done, and program designs for year 2001 are being implemented. Anticipating summer 2001 problems, AB 970 (2000) provided funds that the Energy Commission, Department of General Services, and other agencies used to develop specific programs that can achieve at least 200 MW of load reductions by next summer. A major new effort is underway to develop a network of communications that will allow building operators to bid load reduction back into the market and to pre-program their building systems to automatically reduce loads in response either to price or to emergency signals from the ISO.

Finally, as awareness of the ongoing state of dysfunction of the wholesale market grew widespread, the Extraordinary Session of the year 2001 Session of the legislature authorized some $800 million in new funds for energy efficiency and other demand responsiveness programs to be spent by the Energy Commission, CPUC, General Services and other agencies.[3] Given the mid-April authorization date the impacts of these programs will only appear as the summer progresses and not likely be fully effective until the summer of 2002. These new programs are focused on energy efficiency measures that reflect the high cost of summer afternoon market prices compared to off-peak prices. These energy efficiency measures will operate through many years since they fund new equipment that persist

---

[3] SBx1-5 and ABx1-29 collectively authorized about $1.1 billion, which the governor reduced to about $800 million to eliminate overlaps.

through time, in contrast to load curtailment programs that accentuate changes in operation of existing equipment.

Rate Design and Interval Metering Efforts

In the former system, the goals of lower average prices, fostering of energy efficiency, and promoting fairness across rate classes predominated rate setting. Most costs were recovered through level, volumetric energy charges. Energy costs are usage-sensitive, and these costs are properly recovered through volumetric charges, but transmission and distribution costs are largely fixed. Traditional rate designs fostered equity and consumer protection principles that remain valid. The new rate design challenge is to foster equity in ways that are compatible with a competitive market structure.

The original AB 1980 rate freeze was concluded for SDG&E by July 1999 and had been expected within the next year or so for SCE and PG&E. As a result, the CPUC conducted "post-transition" ratemaking proceedings to develop improved rates and to clarify the energy procurement responsibilities of the UDCs. D.00-06-034 expressed the need to expose end-users to hourly energy prices, and adopted a provision requiring that any end-user with an interval meter be billed for commodity energy on the basis of hourly market prices. Just as this decision was made, PX prices were exploding and have continued at extremely high levels ever since.

After long efforts to hold the line of assigning energy procurement costs to end-users, the Governor and CPUC have decided that ratepayers must be asked to accept at least some portion of the wholesale market expenditures made by UDCs, DWR, and CAISO on their behalf. AB1x-1 both authorized DWR to conduct energy procurement activities on behalf of UDC bundled service customers and committed that General Fund expenditures used by DWR for these power purchases would be refunded by revenues collected from ratepayers. In determining how rates would be raised the average of four cents per kWh authorized by D.01-01-018 and D.01-03-082, the CPUC is conducting a rate design phase of the Rate Stabilization proceeding. Tentative goals put forward by parties include equity, energy conservation and reliability. The Energy Commission has advocated introduction of real-time pricing in a limited first step toward broader use of the concept of market-based pricing to achieve demand responsiveness.[4]
As a result of the very high prices still persisting in the wholesale market, the change in rate design climate induced by AB1x-1, and the AB1x-29 funding for RTP meters, the CPUC

---

[4] The Energy Commission testimony in A.00-11-038 etal. proposes that an RTP supplemental agreement to base tariffs be available to each eligible end-user. The key eligibility requirement is the existence of an appropriate package of RTP metering equipment. AB1x-29 provides $35 million in General Fund monies to install RTP metering for all end-users >200 kW. The Energy Commission's intent is for these meters to be installed beginning summer 2001 to be completed by the fall of 2001. End-users agreeing to participate in this RTP supplement would be incented to reduce load whenever market clearing prices were higher than base TOU rates, which the Energy Commission expects during system peak conditions.

now faces fundamental questions about the degree to, and the conditions under which, end-users should be exposed to market prices. Regulatory policy makers and legislative leaders have to rethink some of the basic elements of market design, such as the tradeoffs between efficiency and equity. The complex issues of rate design and interval metering deployment will take time to be resolved and further time to be implemented. This means that fundamental rate-based response to price signals for most end-users is still years away because of the decision-making lag time and the deployment schedules that will be required. Until this effort is completed, short term programs like those discussed above will have to be the main elements that actually provide demand responsiveness.

Conclusions

How much demand responsiveness will be achieved and by when is hard to estimate. The level will depend upon: funding and/or mandates for demand responsiveness programs, the effectiveness of program design, coordination among several separate organizations, commitments to market-based commodity energy rate designs, technology developments affecting performance and cost of needed equipment, and consumer education to make end-users aware of these programs and the balance of costs/benefits of participation.

A mix of programs is necessary, because different consumers have differing levels of interest, ability and incentive to participate in the short-term market. It is crystal clear that the level of interruptions that took place in the second half of 2000 and early 2001 for interruptible rate participants is unacceptable to the vast majority of commercial and industrial participants. Opt-out provisions authorized by the CPUC in D.01-04-006 will be exercised by many participants reducing the aggregate capacity of these mainstays of the ISO's load curtailment capability. Much greater consumer awareness and preparation through general consumer education and targeted marketing for advanced metering opportunities are needed in advance of general consumer exposure to rates based on wholesale market prices.

In the short run, load reductions are dependent upon end-users responding to recruitment efforts for new utility and ISO programs. Recruitment will need to utilize the "carrot" of incentive payments rather than the "stick" of high prices. Voluntary appeals helped in summer of 2000, but such efforts could wear thin over time, and the long-term goal is to have demand reductions rewarded when they contribute to an overall more efficient market. as a result of strenuous efforts by current participants in interruptible rates to opt out of the interruptible program because it operated differently than participants expected them to, it makes sense to attempt to have end-users voluntarily participate in near term programs that are compatible with longer term economic forces. This means incentive-based programs tied to market prices with the end-user offered the flexibility to determine when and how to respond.

In the longer run, most consumers will not use much of their scarce time on demand responsiveness, so technology must make it simple to implement. Significant demand responsiveness depends upon: (a) pricing signals that can electronically trigger adjustment in loads for selected circuits and/or appliances, (b) installation of programmable controllers/actuators in appliances and equipment, (c) rate designs that implement hourly pricing coupled with interval meters that reward consumers that actually respond to price signals, (d) the role of the utility as the automated metering system investor or default energy provider, and (e) consumer education that is at least as extensive as those undertaken in 1998 for direct access and the new market structure.

As greater demand responsiveness is introduced into the market, system planners and operators will need new analytic techniques to predict the load reductions that will occur when prices get high. The SB 1388 (Chapter XXX, Statutes of 2000) research can provide concrete estimates of likely consumer response to time-of-use rates. Assessment of actual consumer response in utility rate design programs in other states can help to validate this research.

Side Bar Illustration

As an example of the core elements of effective demand responsiveness, consider the following illustration of end-user response.

> *John Jones operates a small business consisting of 2,500 square feet in a strip mall. The establishment is metered individually, and he pays his own utility electricity bills. The utility is converting his accounts to hourly energy pricing. Mr. Jones cannot make unilateral changes in his leased facility, but his landlord agrees that he can change out the thermostat for the air conditioning systems and change operating practices to save money.*
>
> *Mr. Jones decides to install a computer controlled thermostat for his roof top package air conditioning units, since he believes that he can tolerate some change in comfort levels when electricity prices are especially high. Mr. Jones acquires computer software, a new master thermostat for the building space, and the connection that links the computer to the new thermostat. Every afternoon the software downloads the PX market clearing prices for the next day. The software uses the desired set point temperature and the maximum "range" in temperature around that point that Mr. Jones believes is tolerable. The software determines when to precool the building and when to let the building temperature float above the set point. By precooling when electricity is cheaper, it can avoid running the system as much when electricity is more expensive. Mr. Jones operates the program in an "initiate" mode to enter his assumptions, but understands that he will have to monitor its performance to see how well it operates. After the program has operated for a few days, Mr. Jones decides his initial temperature swing is too wide, so he narrows the range somewhat, and then lets the system operate*

once again on its own. After a couple of weeks he is reasonably satisfied that the system does not over cool or undercool his building.

One day Mr. Jones hears from the radio that electricity supplies are expected to be especially tight because of forecasted hot weather. He is not sure what to do differently from using his price responsive thermostat control as normal, so he goes about his business. Later that morning he notices that it seems especially cool in his building, so he operates the software program in a "explain" mode. Because prices are expected to be so high in the afternoon the software program is following an especially severe precooling strategy. Satisfied, he exits the program and goes about his business for the day. Later he notices that it is somewhat warm in his building, but he assumes that the software is doing the best that it can under the circumstances. At the end of month, he is pleasantly surprised that his electricity bill has not increased as much as he was told it would be by the utility in its consumer education literature.

This tale of Mr. Jones illustrates the approach to adaptive price response that can be broadly successful over the long term. It focuses on computer software packages and appliance controllers that respond to the decision rules that are programmed into them, rather than presuming that people have the patience to manually track and react to prices.

Appendix B
Wholesale Electricity Pricing in a Sustainable Market

Electricity prices are dependent on many factors – generation cost, opportunity costs for suppliers, value to consumers, and the efficiency of the market in communicating between suppliers and consumers. This report examines the costs of production and the efficiency of the market. The goal is to explain some of the elements needed for creating a long-term sustainable market for electricity.

Any market design must provide generators with enough revenue to maintain operation of some of the existing infrastructure and attract additional investment as needed. The thesis of this report is that even if we can establish a reasonable cost of generation, it is still extremely difficult to develop a market design that will send the appropriate price signals to generators. The difficulty stems from the natural features of electricity. For example, electricity cannot be stored like water or grain. Futhermore, electricity is not just a commodity, it is also a service. The providers of this service do much more than just generate kilowatt hours.

This report first discusses what products and price signals the market needs to deliver. The report then illustrates the price levels that an ideal market would likely produce if California were to have a sustainable market.

A Failed Experiment

As of this writing in June of 2001, some of the markets established under California's 1996 restructuring law, AB 1890, continue to operate. However, the primary energy market no longer operates. The Power Exchange (PX) ceased to function at the end of January and subsequently filed for bankruptcy protection. The markets managed by the Independent System Operator (ISO) still function, although public disclosure of energy prices was suspended until only recently. Late in May, the ISO's real-time energy market resurfaced with published prices, but the market structure envisioned by AB 1890 is no longer being pursued.

The failure of the AB 1890 structure results from an explosion of wholesale electricity prices that began in the third week of May 2000. During the summer of 2000, a day or two of hot weather would push prices in the PX to levels seldom if ever, seen before in its two-year history. In June of 2000, the total amount spent for energy and ancillary services in the PX and ISO markets reached an astonishing (at the time) $3 billion. The comparable total for June of 1999 was only $664 million. Prices seemed to be moderating at times during the remainder of the summer and into early fall, but high prices and low reserve margins returned with renewed vigor in November and December despite cool weather and fairly low seasonal demand.   Total costs in the PX and ISO markets reached $5.5 billion for December.

Around this time, the financial resources of California's major utility companies were nearing exhaustion. The State of California, through the Department of Water Resources (DWR), had to step in and begin buying on behalf of consumers as of January 17, 2001. DWR has spent $50 - $70 million a day for the electricity needed to make up the difference between what the utility companies could generate with their own resources and the utility customers demand. This suggests that prices are higher than they were in December of 2000, even with weather that was so mild as to require little space heating or cooling.

So far, consumers have not been exposed to the full brunt of high wholesale electricity prices, which has been borne by the utilities and DWR. Pacific Gas and Electric Company, the largest utility in California and the United States, filed for bankruptcy on April 6, 2001.

Some believe that the regulated utility system that existed prior to restructuring would be difficult or impossible to restore. Therefore, a re-examination of market structures with a view to producing more affordable, more sustainable and more rational pricing is timely. The Federal Energy Regulatory Commission has found that at least some of the prices in the California market of 2000 were "unjust and unreasonable" under the Federal Power Act. In order to understand how "unreasonable" the electricity prices were in the market, we need to explore what price levels might be considered reasonable in a functionally competitive market.

Important Market Design Features

With restructuring, electricity generation was expected to become more like other industries—prices would be determined by supply and demand, and investors would risk their capital without any assurance from the government that they would see positive cash flow. The designers of the restructured market expected to make the industry more competitive and efficient. Higher efficiency would mean lower prices for consumers.

The design of the restructured electricity market relied extensively on uniform price auctions. In this type of auction, suppliers are asked to offer quantities of output and corresponding prices. The offers are accepted in merit order of price, until all the demand is met. All suppliers whose bids were accepted are paid the amount of the highest accepted bid, called the Market Clearing Price. The rationale for a uniform price auction, as opposed to one in which suppliers are each paid according to what they bid, is that bids there is a better chance that bids will be cost-based. In theory, generators have an incentive to make their bids equal to production cost, because bidding in this manner gives them the best chance of being selected in the auction. Each generator need not be overly concerned that acceptance of its cost-based bid will result in running at no profit, because it can at least hope that the bid of some higher cost generator will set the clearing price that all bidders are paid. Ideally, the uniform price auction should result in the selection of the combination of generators in each hour that meets demand at the least cost, not just least price.   This is known as "economic dispatch," and it was also the ideal when generation was controlled by regulated monopolies.

In a perfect system, prices would not be influenced by market power, but they would occasionally increase to high levels due to "scarcity rent." When demand exceeds supply, the available electricity can be rationed by increasing the price. The increase necessary to reduce demand enough to equal supply is called "scarcity rent." A price established with scarcity rents could be many times higher than the production cost of electricity since most consumers' place a high value on the power supply. Scarcity rent in the pricing of a vital commodity or service seems harsh to some consumers, but arguably it is necessary for the system to work.

If prices were always set by marginal production cost, generators would likely receive price streams that are insufficient to keep them in business or bring new generators into the market. The differences in efficiency among generators are considerable, but not large enough to cover fixed cost and profit requirements for the most efficient new generation, which tends to have the highest fixed cost. Less efficient, older generation facilities usually have lower fixed costs, but if they commonly set market clearing price with bids that approximate their production costs, then they will make hardly any money toward fixed costs and profit. With scarcity rent, occasional price spikes can provide enough revenue that all needed generation can cover its revenue requirements. The spikes also provide strong price signals whenever new generation is needed. The entry of new generation moderates scarcity and scarcity rent spikes until older generators are retired or demand again starts to outpace supply. Scarcity rent thus helps to assure that demand and supply stay in rough balance.

Although scarcity rent is not a problem from the point of view of economic theory, it may be a problem in the real world. First, it can be difficult to distinguish scarcity rents from market power. Even if it is entirely legitimate, scarcity rent may produce electricity prices that are disproportionate to what people are accustomed to paying. Generators and institutions that provide their financing may consider a price stream characterized by cost-based prices with occasional periods of scarcity rent as an investment risk. A spiky revenue stream provides sufficient income when averaged over a year or several years, but generators usually have to meet fixed cost obligations such as debt service and payroll every month. Any business that cannot demonstrate a steady income will have trouble borrowing money, and if a lender can be found, the money will carry a high interest rate.

Another problem with relying on scarcity rents to reward generators in the market is that scarcity may not be compatible with the reliability requirements of the electricity system. A voltage collapse will occur if the actual physical demand on the system significantly exceeds the energy generators are supplying. A few seconds of imbalance can be enough to cause widespread blackouts. In a blackout, everyone is deprived of electricity regardless of what they are willing to pay, and the economic consequences can border on disaster.

This is not to say that scarcity should not be allowed, or that scarcity should not be allowed to affect prices. However, experience has not yet demonstrated that economic scarcity in an electricity system can be compatible with system reliability in an engineering sense. Perhaps the two can be compatible in the future, but this would likely require far more sophisticated metering and control over electricity use than is commonly practiced today.

Without doubt, energy has been scarce at times since the spring of 2000, but it is also true that the electricity market in California was and remains far from ideal. In 2000, few supply bidders controlled practically all the pivotal megawatts of generation, and they each knew a great deal about probable demand levels and what their competitors were doing. They could often submit bids well above production cost and be fairly well assured that these bids would be accepted. The same sellers still retain substantial power to dictate prices.

Two Products: Energy and Capacity

A fair and efficient market would over time provide generators with revenue streams sufficient to cover their full variable and fixed costs, and there would be only as much generation capacity as the public is willing to reward. Power plant investors would receive returns equal to what they could get on other investments of similar risk. When prices vary in a range that is close to meeting these revenue requirements, the market would appear to be performing well. The 1999 California market prices were generally at levels that meet these criteria.

In wholesale transactions prior to restructuring, generators could receive two revenue streams: energy payments and capacity payments. The restructured market primarily focuses on energy payments, but capacity payments are still available under some circumstances. Energy payments are for kilowatt-hours produced, so they are denominated in cents/kWh or $/MWh. The $/MWh form is usual in wholesale trade. Capacity payments are generally made to a generator just to be ready to produce energy, and they are usually denominated in $/kW.

Capacity payments strike some people as strange, since capacity is generally not priced in other industries. However, electricity has few similarities to other products. Electricity cannot be stored for most purposes and almost everyone wants it to be instantly available, no matter how many other people want it at the same time. Refrigerators, washing machines, computers and the like accept no substitutes. This implies that both the capacity that is producing electricity at any time and the idle capacity that stands ready to produce are providing vital services. Capacity is like having a car in the garage—it is useful even when you are not using it, because it is available.

In power supply contracts, capacity terms and capacity payments are useful for assuring reserves and allowing the ability to follow variations in load. Meeting load in real time requires that a certain percentage of unloaded generation be maintained to meet contingencies. Meeting load in the future requires reserves against the possibility that the actual load will be higher than expected. Meeting consumer load over any span of time requires a range of generation output up to the maximum load that may occur in that period, even though it may be sustained only for a short time.

In the California markets, capacity payments have been offered only for "ancillary services" (mainly the service of keeping some extra capacity ready to run hour by hour). Ancillary services are short-term reliability services provided by generation that is not producing energy. Under restructuring, no capacity payments have been offered for the services of providing energy to meet demand or being available to meet fluctuations in demand that encompass periods longer than one hour.

Capacity Planning

An important difference between paying generators only for energy or paying them for energy and capacity (other than ancillary services) is that in the latter case someone must decide how much capacity is needed. This is not a problem with energy. Consumers decide how much energy they need minute by minute by flicking switches. The need for capacity, on the other hand, is determined more by anticipating how much energy consumers will demand in the near or mid range future. Nobody can be sure how many MW of demand consumers will place on the electricity system in the future, but professional electricity planners can make informed estimates.

Without capacity payments, energy prices can determine when new capacity is added to the system. If prices are high enough, power plant developers will recognize a business opportunity and build new plants. A drawback is the price spike phenomenon caused by scarcity rents. Another drawback is the "boom and bust" cycle that may seldom sustain anything close to a reasonable balance between supply and demand.

Capacity payments are not the only way to solidify a relationship between generation and load. Fixed prices for energy can accomplish much the same objectives, although with less flexibility, provided they have sufficient duration and provide a sufficient margin above the variable costs of production. Call options are another alternative. In a call option, a load-serving entity pays a generator a retainer in return for the generator's promise to supply energy at a prearranged price when called upon.

Generator Revenue Needed for Sustainable Market

The revenue requirement of an existing power plant is the income stream it needs to operate as a viable business. The revenue requirement of a proposed power plant is the income stream that would allow it to operate as a viable business once it is constructed. Like other businesses, power plants can experience good times and bad times, but if they fail to meet their revenue requirements over a span of years, the public cannot rely on them. Existing plants can be deactivated and their parts sold, new projects can be put on hold.

Since new plants are always needed over the long term, either to meet load growth or to replace older plants as they wear out, revenue requirements are best expressed as the costs to build, pay for, and operate a new plant. Nearly all new generating plants of substantial size that might be built in the next decade or so will rely on either simple cycle or combined cycle gas turbines, so their revenue requirements count most.

Cost estimates for combined cycle plants tend to be around $600/kW for a 500 MW plant. **Table B-1** shows some of the costs estimates the Energy Commission's Siting Division has received from project developers. The estimates may not be comparable, because they do not rely on any standard methodology. All the plants listed in **Table B-1** are all combined-cycle units that are medium to large in size. Larger plants tend to be less expensive than smaller plants on a $/kW basis.

Combined cycle plants can be highly efficient and cost effective if they are run continuously at high output. The varying nature of electrical loads dictates that not all plants can run in this manner. For less intensive use, simple cycle plants are more economic. Estimates in the 1999-2000 Gas Turbine World Handbook indicate that the cost of a simple cycle plant, on a $/kW basis, may be about 60 percent of what a combined cycle costs. Therefore, we will characterize the cost of a simple cycle plant as $360/kW (60 percent of $600/kW). This comports well with a published estimate of $356/kW for a simple cycle project in Georgia.

Table B-1
Cost Estimates for Power Plant Projects
(all are gas-fired combined cycle)

	MW	Cost ($ Million)	$/kW	County
Blythe	520	250	481	Riverside
Elk Hills	500	300	600	Kern
La Paloma	1048	500	477	Kern
Long Beach	500	300	600	Los Angeles
Los Medanos	500	300	600	Contra Costa
Midway-Sunset	500	250	500	Kern
Mountain View	1056	550	521	San Bernardino
Otay Mesa	510	350	686	San Diego
Sutter	500	275	550	Sutter
Three Mountain	500	300	600	Shasta

The financing of construction costs, plus fixed operation and maintenance costs, determine the revenue stream above variable operating costs that is needed to make a new power plant financially viable. Plants are usually financed with a combination of debt and equity. The proportions of each vary, with projects that are thought to be riskier usually requiring more equity. Interest rates on debt and required rates of return on equity also vary widely; higher risk requires higher return.

Estimates of what new power plants should cost to build and finance are as shown on **Table B-2**. These estimates are the middle of a range in which revenue requirements could be 15 percent higher or lower.

Table B-2
Financial Assumptions and
Resulting Revenue Requirements
For construction of new gas-fired power plants in California

	Simple Cycle	***Combined Cycle***
Construction Cost ($/kW)	360	600
Debt/Equity	60/40	60/40
Amortization Period (yrs.)	20	20
Interest Rate on Debt	9.0%	8.5%
After-tax Return on Equity	15.1%	14.8%
Tax Rate	40%	40%
Non-Capital Fixed Cost ($/kW-yr.)	8	15
Revenue Requirement ($/kW-yr.)	60	100

Table B-3 shows income streams, expressed in average energy and capacity prices, that would be sufficient to support the revenue requirements postulated in **Table B-2**. For example, if generators rely on energy payments only (capacity payments = zero), a generation infrastructure consisting of combined cycle and simple cycle gas-fired power plants can be sustained if energy prices average about $293/MWh for 2.5 percent of the hours and $41.44/MWh over the full course of the year. This assumes both kinds of plants can earn $5/kW-yr in the ancillary services markets.

In another example, if all generators received $40/kW-yr in capacity payments, energy prices could average from $110/MWh during the highest priced 2.5 percent of the hours to $36.88/MWh over the full course of the year. Rationales for capacity payments include meeting commitment targets, such as load plus operating reserve; and meeting planning reserve margins, such as anticipated peak load plus 15 percent. If capacity payments were assured for several years, revenue requirements might be reduced, because the guaranteed revenue stream would tend to allow the project to be financed at lower rates.

Spot market energy prices would vary around the averages. Over the course of the year there might be a few hours when the price of energy is $0/MWh. There also might be a few hours when the price is $1000/MWh or more.

Table B-3
Average Energy Prices Needed to Meet Revenue Requirements

Simple Cycle

Natural Gas Fuel Price ($/MMBtu)				$4.50
Capital Cost ($/kW)				$360
Heat Rate (Btu/kWh)				9300
Non-Fuel Variable O&M ($/MWh)				$4.00
Total Variable Op. Cost ($/MWh)				$41.85
Revenue Requirement ($/kW-yr)			$60.00	
Ancillary Service Earnings ($/kW-yr)			$5.00	
Net Revenue Requirement ($/kW-yr)				$55.00
Capacity Payment ($/kW-yr)		**0**	**20**	**40**
Capacity Factor	**2.5%**	$292.99	$201.67	$110.34
	5%	$167.42	$121.76	$76.10
	10%	$104.64	$81.80	$58.97
	40%	$57.55	$51.84	$46.13

Capacity factor here refers to the fraction of the year during which the capacity is producing energy.

Combined Cycle

Natural Gas Fuel Price ($/MMBtu)				$4.50
Capital Cost ($/kW)				$600
Heat Rate (Btu/kWh)				6800
Non-Fuel Variable O&M ($/MWh)				$4.00
Total Variable Op. Cost ($/MWh)				$30.60
Revenue Requirement ($/kW-yr)			$100.00	
Ancillary Service Earnings ($/kW-yr)			$5.00	
Net Revenue Requirement ($/kW-yr)				$95.00
Capacity Payment ($/kW-yr)		**0**	**20**	**40**
Capacity Factor	**40%**	$57.71	$52.00	$46.30
	60%	$48.67	$44.87	$41.06
	80%	$44.16	$41.30	$38.45
	100%	$41.44*	$39.16	$36.88

*Gas price sensitivities: If gas price average is $4.50, the breakeven energy price ($/MWh) for a combined cycle plant that runs at 100 percent capacity factor is $41.44; If gas price average is $6.00, the breakeven energy price ($/MWh) for a combined cycle plant that runs at 100 percent capacity factor is $51.64; if gas price average is $8.00, the breakeven energy price ($/MWh) for a combined cycle plant that runs at 100 percent capacity factor is $65.24

In a real system, combined cycle plants would be used to meet the load levels that are sustained over long periods and large numbers of hours, while simple cycle technology would be used for shorter duration "peaking" loads. **Figure B-1** shows the prices needed to sustain both kinds of generators over the fractions of a year during which they would likely be active. Loads that exist during 40 percent of the hours or less would be met by simple cycle generation. **Figure B-1** also shows a plot derived from the actual PX prices for the 12 months spanning November 1999 through October 2000. Note that the actual prices were far higher than what should be necessary to sustain a healthy generation infrastructure. This lends support to the finding of the Federal Energy Regulatory Commission that prices have not been "just and reasonable," the electricity pricing standard required under federal law.

Figure B-1
Average Energy Prices
Actual 11/1/99--10/31/00 vs. two just and reasonable revenue streams

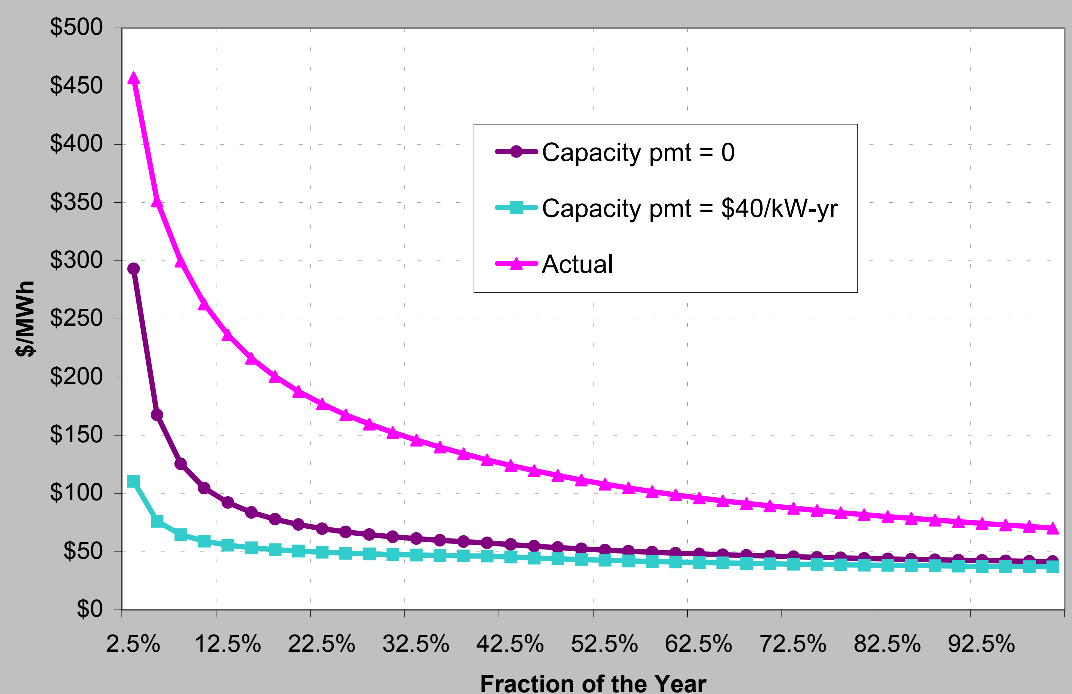


Table B- 4 shows imputable earnings of a highly efficient combined cycle power plant on the energy prices that were paid in the Power Exchange in 2000. Earnings are calculated as the difference between PX price and operating cost based on month-by-month average gas prices in each region. As **Table B-3** indicates, such a plant needs to recover about $100/kW-yr in earnings to cover costs and return a fair profit to investors. Obviously, a plant could have earned far more than $100/kW over the year (assuming it could collect from the PX, although this consideration applies only to November and December).

Table B-4
Imputable Earnings of a Power Plant Running at 6800 Btu/kWh
Per kilowatt of capacity, on PX day-ahead prices of 1/1/00 - 12/31/00

Month	Monthly NP15	Cumulative NP15	Monthly UMCP	Cumulative UMCP	Monthly SP15	Cumulative SP15
Jan-00	$7.33	$7.33	$7.17	$7.17	$5.67	$5.67
Feb-00	$4.96	$12.29	$5.02	$12.19	$5.04	$10.71
Mar-00	$3.51	$15.80	$3.86	$16.05	$4.32	$15.03
Apr-00	$2.74	$18.54	$2.83	$18.88	$5.83	$20.86
May-00	$14.97	$33.51	$14.87	$33.75	$19.61	$40.47
Jun-00	$65.91	$99.42	$61.31	$95.06	$59.16	$99.63
Jul-00	$37.33	$136.75	$51.85	$146.91	$44.30	$143.93
Aug-00	$72.84	$209.59	$95.12	$242.03	$86.18	$230.11
Sep-00	$50.51	$260.10	$54.19	$296.22	$47.17	$277.28
Oct-00	$43.59	$303.69	$43.47	$339.69	$32.62	$309.90
Nov-00	$77.32	$381.01	$84.41	$424.10	$47.24	$357.14
Dec-00	$120.10	$501.11	$163.08	$587.18	$51.22	$408.36

Note: Assumes $2.50/MWh variable O&M and 100 percent availability factor.
NP15 is a price series representing Northern California.
UMCP means Unconstrained Market Clearing Price, and it represents what prices might have been statewide had transmission constraints not altered them.
SP15 is a price series representing Southern California. The numbers in the table are not the prices, but rather earnings calculated from the prices.

Conclusion

The market structure consisting of the Power Exchange as a day-ahead and day-of spot market and the ISO's market for real-time energy and ancillary services was not successful. Either of the lower two lines on **Figure B-1** represents prices that would be indicative of a healthy wholesale electricity market. The lower of these two lines assumes a substantial capacity payment. The upper "Actual" line, represents the prices observed in California's market as it was designed and operated. If the last few months of the market's performance were included in the graph, the comparison would only show a sharper variance between what could have been hoped for and what actually occurred. As the market recovers, it will need a comprehensive redesign. A structure should be considered in which hour by hour energy payments are kept within a range reasonably related to production costs, while fixed costs and profit are covered to a greater degree by capacity payments.